PB80-187958

Multimedia Assessment of the Natural Gas Processing Industry

TRC Environmental Consultants, Inc.
Wethersfield, CT

Prepared for

Industrial Environmental Research Lab.
Research Triangle Park, NC

Apr 79

U.S. Department of Commerce
National Technical Information Service
NTIS

United States
Environmental Protection
Agency

Industrial Environmental Research
Laboratory
Research Triangle Park NC 27711

EPA-600/2-79-077
April 1979

PB80-187954

Research and Development

Multimedia Assessment of the Natural Gas Processing Industry

REPRODUCED BY
NATIONAL TECHNICAL
INFORMATION SERVICE
U. S. DEPARTMENT OF COMMERCE
SPRINGFIELD, VA. 22161

RESEARCH REPORTING SERIES

Research reports of the Office of Research and Development, U.S. Environmental Protection Agency, have been grouped into nine series. These nine broad categories were established to facilitate further development and application of environmental technology. Elimination of traditional grouping was consciously planned to foster technology transfer and a maximum interface in related fields. The nine series are:

1. Environmental Health Effects Research
2. Environmental Protection Technology
3. Ecological Research
4. Environmental Monitoring
5. Socioeconomic Environmental Studies
6. Scientific and Technical Assessment Reports (STAR)
7. Interagency Energy-Environment Research and Development
8. "Special" Reports
9. Miscellaneous Reports

This report has been assigned to the ENVIRONMENTAL PROTECTION TECHNOLOGY series. This series describes research performed to develop and demonstrate instrumentation, equipment, and methodology to repair or prevent environmental degradation from point and non-point sources of pollution. This work provides the new or improved technology required for the control and treatment of pollution sources to meet environmental quality standards.

EPA REVIEW NOTICE

This report has been reviewed by the U.S. Environmental Protection Agency, and approved for publication. Approval does not signify that the contents necessarily reflect the views and policy of the Agency, nor does mention of trade names or commercial products constitute endorsement or recommendation for use.

This document is available to the public through the National Technical Information Service, Springfield, Virginia 22161.

TECHNICAL REPORT DATA
(Please read Instructions on the reverse before completing)

1. REPORT NO.
EPA-600/2-79-077

2.

3. RECIPIENT'S ACCESSION NO.
PB80 187958

4. TITLE AND SUBTITLE
Multimedia Assessment of the Natural Gas Processing Industry

5. REPORT DATE
April 1979

6. PERFORMING ORGANIZATION CODE

7. AUTHOR(S)
Willard A. Wade III

8. PERFORMING ORGANIZATION REPORT NO.

9. PERFORMING ORGANIZATION NAME AND ADDRESS
TRC - The Research Corporation of New England
125 Silas Deane Highway
Wethersfield, Connecticut 06109

10. PROGRAM ELEMENT NO.
1AB604

11. CONTRACT/GRANT NO.
68-02-2615, W.A. 2

12. SPONSORING AGENCY NAME AND ADDRESS
EPA, Office of Research and Development
Industrial Environmental Research Laboratory
Research Triangle Park, NC 27711

13. TYPE OF REPORT AND PERIOD COVERED
Task Final; 9/77 - 11/78

14. SPONSORING AGENCY CODE
EPA/600/13

15. SUPPLEMENTARY NOTES Project officer I. A. Jefcoat is no longer with IERL-RTP; for details contact Bruce A. Tichenor, MD-62, 919/541-2547.

16. ABSTRACT
The report gives results of an assessment of the air and water pollution potential of the natural gas processing industry, based on a review of publicly available literature. It reviews natural gas processing operations and discusses the potential air and water emissions from the industry. It describes acid gas removal, dehydration, purification, and stripping unit operations, primarily to indicate their potential for air and water pollution. It presents historical production data and discusses future trends in applications of new techniques. It reviews Federal and State regulations affecting the industry and discusses their limitations and reporting requirements. It discusses the impact of the myriad rules, regulations, and reporting requirements on obtaining quantifiable data on the industry. It estimates air emissions for each criteria pollutant for the industry nationwide, as well as for Texas and Louisiana, the two largest producing states. It shows the significance of emissions from natural gas processing operations relative to other industrial sectors. It compares these estimates with overall mass balance calculations based on published production and distribution data. It discusses, generally, the water pollution potential of the industry and describes shortcomings in available data.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group	
Pollution	Regulations	Pollution Control	13B	05D
Natural Gas		Stationary Sources	21D	
Industrial Processes		Natural Gas Processing	13H	
Assessments		Environmental Assessment	14B	
Dehydration			07D,07A	
Purification		Acid Gas	14G	
Stripping		Criteria Pollutants		

18. DISTRIBUTION STATEMENT
Unlimited

19. SECURITY CLASS *(This Report)*
Unclassified

20. SECURITY CLASS *(This page)*
Unclassified

21. NO. OF PAGES
147

22. PRICE

EPA-600/2-79-077

April 1979

Multimedia Assessment of the Natural Gas Processing Industry

by

Willard A. Wade III

TRC - The Research Corporation of New England
125 Silas Deane Highway
Wethersfield, Connecticut 06109

Contract No. 68-02-2615
W.A. 2
Program Element No. 1AB604

EPA Project Officer: Irvin A. Jefcoat

Industrial Environmental Research Laboratory
Office of Energy, Minerals, and Industry
Research Triangle Park, NC 27711

Prepared for

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Research and Development
Washington, DC 20460

CONTENTS

1. Introduction 1

2. Summary and Conclusions 2

3. Industry Description 4

4. Present Environmental Regulations Affecting The Natural Gas Processing Industry 19
    - Federal Regulations 19
        - Air Pollution 19
        - Water Pollution 19
    - State Regulations - Louisiana 21
        - Water Pollution Control 21
        - Air Pollution Control 22
        - Solid Waste 23
    - State Regulations - Texas 23
        - Water Pollution Control 23
        - Air Pollution Control 24
        - Solid Waste 25

5. Natural Gas Processing Operations 28
    - Liquid Separation 28
    - Acid Gas Removal 28
        - Amine Processes 31
    - Dehydration 31
        - Liquid Desiccant Absorption 33
        - Solid Desiccant Adsorption 33
        - Injection of Hydrate Point Depressants 36
        - Expansion Refrigeration 36
    - Sulfur Recovery 38
    - Tail-Gas Conditioning 39
        - Wet-Reduction Processes 41
            - Shell SCOT Process 41
            - Parson's Beavon Process 41
            - Pritchard's Clean Air Process 43
            - Trentham's Trencor-M Process 43
        - Wet-Oxidation Processes 43
            - Wellman-Lord Process 43
            - USBM Citrate Process 46
        - Wet-Extension Processes 46
            - IFP Process 46
            - Stauffer Aquaclaus Process 46
            - Townsend Process 48
            - ASR Sulfoxide Process 48

CONTENTS
(Continued)

5. Natural Gas Processing Operations (continued)
        Dry-Extension Processes 48
            SNPA/Lurgi Sulfreen Process 48
            Amoco CBA Process 49
        Dry-Oxidation Processes 49
            Shell SFGD Process 49
            Westvaco Process 49
            SNPA/TOPSOE Catalytic-Oxidation Process 49
    Heavy Hydrocarbon Stripping 50
        Absorption 50
        Refrigerated Absorption 52
        Refrigeration Process 52
        Compression 55
        Adsorption 55
        Cryogenics/Turbo-Expansion 55
    Future Processing Trends 59

6. Air Pollution Aspects of the Domestic Gas Processing Industry 61
    Air Emissions in the Natural Gas Processing Industry . . 61
        Sulfur Dioxide 62
        Hydrocarbons 62
        Hydrogen Sulfide 65
        Glycol 66
    Texas Emission Inventory 66
    Louisiana Emission Inventory 69
    Compliance Status of Natural Gas Plants 82
    Process Sources of Air Pollution 82

7. Water Pollution Aspects of the Domestic Natural Gas Processing Industry 86
    Produced Water 86
    Cooling Water 86
    Other Sources of Water Pollution 89
    Wastewater Treatment 89

References 91

Appendices

A. List of Natural Gas Processing Plants, Capacities, Products as of January 1, 1977 93
B. List of Conversion Factors, English-SI Metric System 113
C. Major Domestic Gas Supply Companies, 1975 115
D. Acid Gas Removal Processes Used in the Natural Gas Processing Industry 119

LIST OF FIGURES

FIGURE		PAGE
1	Location of domestic natural gas processing plants, 1977	5
2	Total U.S. marketed production of natural gas and interstate domestic gas production 1955-1976	7
3	Overall material balance for natural gas production - 1976	11
4	Graph of U.S. natural gas reserves	15
5	History of total interstate gas supply	16
6	Graphs of supply and demand for various NGL products	17
7	Flow diagram of the natural gas industry	29
8	Flow diagram for a three-stage wellhead separation unit	30
9	Flow diagram of the amine sweetening process	32
10	Flow diagram of the glycol dehydration process . . .	34
11	Flow diagram of the adsorbent dehydration process . .	35
12	Flow diagram of the glycol injection dehydration process	37
13	Flow diagram of a Claus sulfur plant	40
14	Flow diagram of the SCOT process	42
15	Flow diagram of the Beavon process	44
16	Flow diagram of the Wellman-Lord process	45
17	Flow diagram of the IFP-2 process	47
18	Absorption plant for natural gasoline	51
19	Flow diagram of the refrigerated absorption process .	53
20	Flow diagram of the refrigeration process	54

LIST OF FIGURES (Continued)

FIGURE		PAGE
21	Flow diagram of the compression process	56
22	Flow diagram of adsorption process	57
23	Flow diagram of the expander cycle	58
24	Louisiana emission inventory, NO_x emissions (1973) vs. gas throughput for the natural gas processing industry	73
25	Louisiana emission inventory, HC emissions (1973) vs. gas throughput for the natural gas processing industry	74

LIST OF TABLES

TABLE		PAGE
1	Domestic Gas Processing Capacities by State as of January 1, 1977	6
2	Supply and Disposition of Gas in the United States, 1955 - 1976	9
3	Production at Domestic Natural Gas Processing Plants for April, 1977	10
4	Overall Size and Capacity of the Natural Gas Processing Industry, 1976	12
5	Capital Investment in the Natural Gas Processing Industry	14
6	Natural Gas Treated for Natural Gasoline and Allied Products, and Quantities and Value of Products Recovered, 1955-1976	14
7	Planned Construction of Domestic Natural Gas Processing Plants as of January 1, 1977	18
8	Outline Summary of Rule 8 of the Texas Railroad Commission	26

LIST OF TABLES (Continued)

TABLE		PAGE
9	Comparison of Domestic Gas Products Extraction Processes	60
10	Comparison of Several Operation Parameters for Absorption vs. Cryogenic Plants	60
11	Comparison of Estimates for Sulfur Dioxide Emissions from Process Sources in the Natural Gas Processing Industry, 1969 vs. 1976	63
12	Comparison of SO_2 Emissions from All Sources	64
13	Estimate of Emissions from Natural Gas Processing, 1976 Plant and Pipe Line Power Generation Equipment .	64
14	Texas Emission Inventory Summary for Natural Gas Processing Plants, 1973 Data	67
15	Point Source Emissions from Industrial Processes Texas Emission Inventory - 1973 Pollutant in Metric (Short) Tons Per Year	68
16	Louisiana Emission Inventory Summary for the Natural Gas Processing Industry, 1975 Data	70
17	Flare Emissions for Natural Gas Processing Industry, Louisiana Emission Inventory, 1973	75
18	Storage Tank Emissions for Natural Gas Processing Industry, Louisiana Emission Inventory, 1973	76
19	Engine Emissions for Natural Gas Processing Industry, Louisiana Emission Inventory, 1973	77
20	Heater Emissions for Natural Gas processing Industry, Louisiana Emission Inventory, 1973	79
21	Emission Factors for Natural-Gas Combustion	81
22	Emission Factors for Heavy-Duty, General-Utility, Stationary Engines Using Gaseous Fuels	81

LIST OF TABLES (Continued)

TABLE		PAGE
23	Point Source Emissions from Industrial Processes, Louisiana Emission Inventory - 1975, Pollutant in Metric (Short) Tons Per Year	83
24	Sources of Wastewater - Natural Gas Processing Operations	87
25	Natural Gas Processing Plants Typical Discharge Characteristics	88

SECTION 1

INTRODUCTION

Natural gas processing is a major activity associated with the energy industry. Once considered a waste product in the extraction and production of crude oil, the sale of natural gas and its associated products is a multibillion dollar business ($27 billion in 1976). The largest single market is industrial, commercial, and residential usage of pipeline natural gas. Chemical and petrochemical industries are making ever-increasing demands on natural gas products which are desirable feedstocks for many of their synthetic operations.

The natural gas processing industry combines many activities, including extraction from the earth, processing to remove undesirable components, and final distribution of the gas and liquid fractions. Many processes have been developed to clean the gas and separate the mixture into saleable products. These processes include acid gas removal, dehydration, and heavy hydrocarbon stripping. Physical and chemical processing steps, such as de-entrainment, liquid or solid absorption, expansion and compression, and refrigeration are used to achieve economic yields of specification products.

Air and water pollution emissions result from the extraction, processing, and distribution aspects of the industry. These emissions are regulated under a variety of state and local regulations. It was the objective of this study to review the available literature on air and water pollution relevant to the natural gas processing industry and to assess, if possible, the overall impact of this industry on the environment.

SECTION 2

SUMMARY AND CONCLUSIONS

Sources of air and water pollution exist at each of the processing steps from extraction and processing to final distribution. Air pollution emissions, mainly hydrocarbons, occur at the wellhead from venting and flaring, miscellaneous leaks in the processing of the gas and from working and breathing losses in storage and handling of the end products. Sulfur dioxide and hydrogen sulfide emissions occur from the extraction and processing of sour natural gas. These emissions are regulated by state and local laws and through the individual State Implementation Plans. Owners of processing plants are required to file reports on operations and emissions on a regular basis. These reports generally consist of emissions estimates based on mass balances of unknown accuracy and emission factors generated by the Environmental Protection Agency. No data were found relating emissions to operating capacities substantiated by source tests.

Water pollution emissions consist of produced water, scrubber and boiler blowdown, and miscellaneous spillage and runoff. Produced water originates in the producing well and is usually very high in salinity. Boiler and cooling water blowdown usually contain anti-scalants and corrosion inhibitors. In many cases varying amounts of the total plant wastewaters are reinjected into the producing strata to maintain well pressure or disposed of in other strata.

Disposal of wastewater in this industry is regulated mainly by state and local laws. State disposal permits are required as a means of protecting useful aquifers from contamination by deep well injection of highly saline wastes. Spill prevention and control plans are required for producing, processing and distribution facilities as a means of limiting and controlling hydrocarbon contamination of receiving waters. There are no federal effluent guidelines which affect the industry. The single toxic substance associated with this industry at this time is chromium. As of yet the industry is not subject to the Toxic Substances Control Act (TSCA) reporting and testing requirements. Reports filed on a regular basis as dictated by state laws are often unclear as to the origin of individual volumes of waste streams within a given plant. The values reported are mostly the result of sample analysis, but the contribution of each operation remains unclear within the scope of this review.

It can be concluded from this literature review that there are quantities of several pollutants, hydrocarbons, SO_2, H_2S, NO_x, being emitted by natural gas processing plants. The reported values are primarily calculated from emission factors and known production volumes. Inventorying of reported emissions is lagging substantially behind the current year and the development of a relationship between this industry and others has been hampered. There is, as of yet, no information available on the fugitive or nonpoint emissions from activities in this industry. It is most likely that fugitive hydrocarbon emissions could be a substantial fraction of the total emissions from the industry.

We estimate that SO_2 emissions have decreased by approximately 20% between 1969 and 1976 (the latest year for which data were available). This was primarily due to the addition of new sulfur recovery facilities at natural gas processing plants. This industry is a source of approximately 15% of the SO_2 emitted nationwide in 1972. This industry is a minor source of the other criteria pollutants.

The survey of Texas and Louisiana emission inventories showed that the natural gas industry is highest in both states as a source of NO_x. Primarily, NO_x emissions are the result of internal combustion engines which power the compression, refrigeration and pumping systems in the plants. The industry in Texas is the greatest source of sulfur oxides but not in Louisiana. Hydrocarbon emissions place the industry as the third highest source in both states.

Process specific wastewater characteristics are uncertain, but the impact of wastewater discharges on the environment appears to be minimal in light of the information currently available.

The development of accurate data on the air and water pollution aspects of the industry can only be developed by instituting a comprehensive testing program. Extrapolation of a few specific tests to apply throughout the industry would be frustrated by the uniqueness of the various plants, which are specifically designed for a given crude gas composition and final product mix.

SECTION 3

INDUSTRY DESCRIPTION

The natural gas industry consists of numerous activities from the wellhead to the end user such as, drilling, extraction, processing, marketing, and distribution. The final products from these plants are pipeline-quality natural gas and natural gas liquids (NGL). The NGL products include ethane, liquified petroleum gases (LPG-butane, propane, and isobutane), natural gasoline and condensate mixtures. Finished products from plants having fractionation capability include finished gasoline, naphtha, jet fuel, kerosene, and distillate fuel oil.(1)

Raw natural gas originates in subsurface strata often under high pressure (in excess of 8.8 MPa (1,000 psia)) and in combination with crude oil (associated or casinghead gas). However, 82% of the domestic gross production of raw natural gas originates from wells dedicated solely to natural gas and natural gas liquids extraction.(2) Raw natural gas hydrocarbons may include only methane and ethane (dry natural gas) or methane to pentanes (wet natural gas). Only 2-5% of domestic gas is classified as 'sour' because of the presence of hydrogen and carbonyl sulfides. Sweet gas contains very little or none of these contaminants. Carbon dioxide, water vapor, nitrogen, helium, and mercaptans may also be present in the raw gas. The liquid phase may include natural gasoline, butane, propane, and saltwater. Approximately 95% of natural gas must be processed (prior to distribution) to separate useful hydrocarbons and to remove undesirable contaminants.

Gas processing plants are usually located in the producing field or in an area common to several gas fields. Figure 1 shows the geographic distribution of the domestic gas processing plants. As of January 1, 1977, there were 763 gas processing plants in the United States.(3) Table 1 shows their location and average daily production by state. A tabulation of all domestic gas processing plants as of January 1, 1977 is included in Appendix A. As shown in Table 1, the average daily throughput for 1976 was 1.4×10^9 cubic meters per day* (1.4 Gcum per day) (48,000 mcfd)**, 0.5 Tcumpy (17.5 trillion cubic feet per year) with a total capacity of 2.0 Gcumpd (73.0 mcfd). Figure 2 shows the marketed and interstate natural gas production from 1955-1976. Texas, Louisiana, Oklahoma, California, New Mexico, and Kansas account for 93% of the total domestic production. Natural gas liquids (NGL) production should reach 2.5×10^5 million cubic meters per day (0.25 Mcumpd) (1.6 mbpd)*** in 1977.

---

*Volume at standard conditions, 0.1 MPa (14.73 psia), 289°K (60°)

**Million cubic feet per day.

***Million barrels per day.

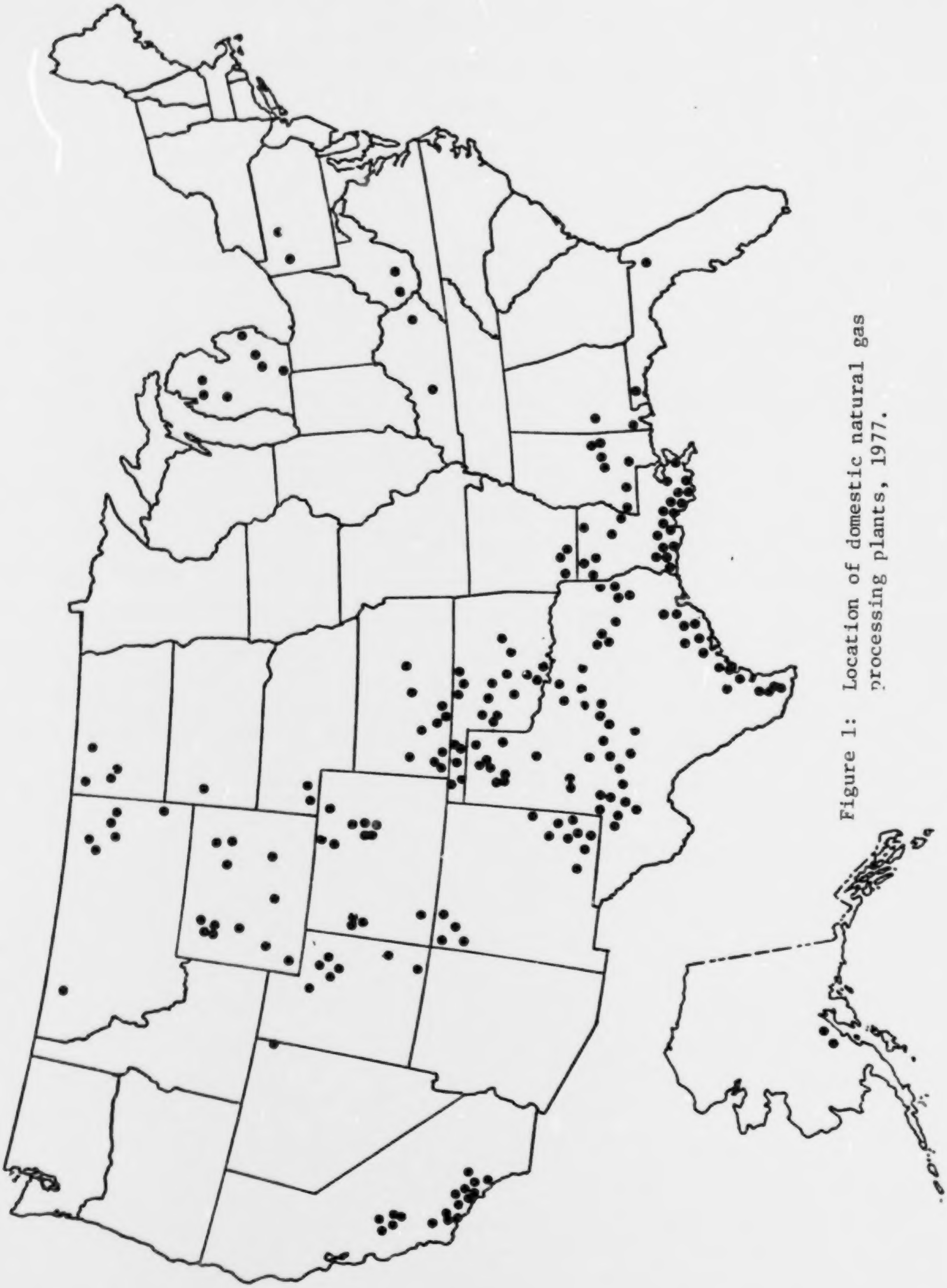


Figure 1: Location of domestic natural gas processing plants, 1977.

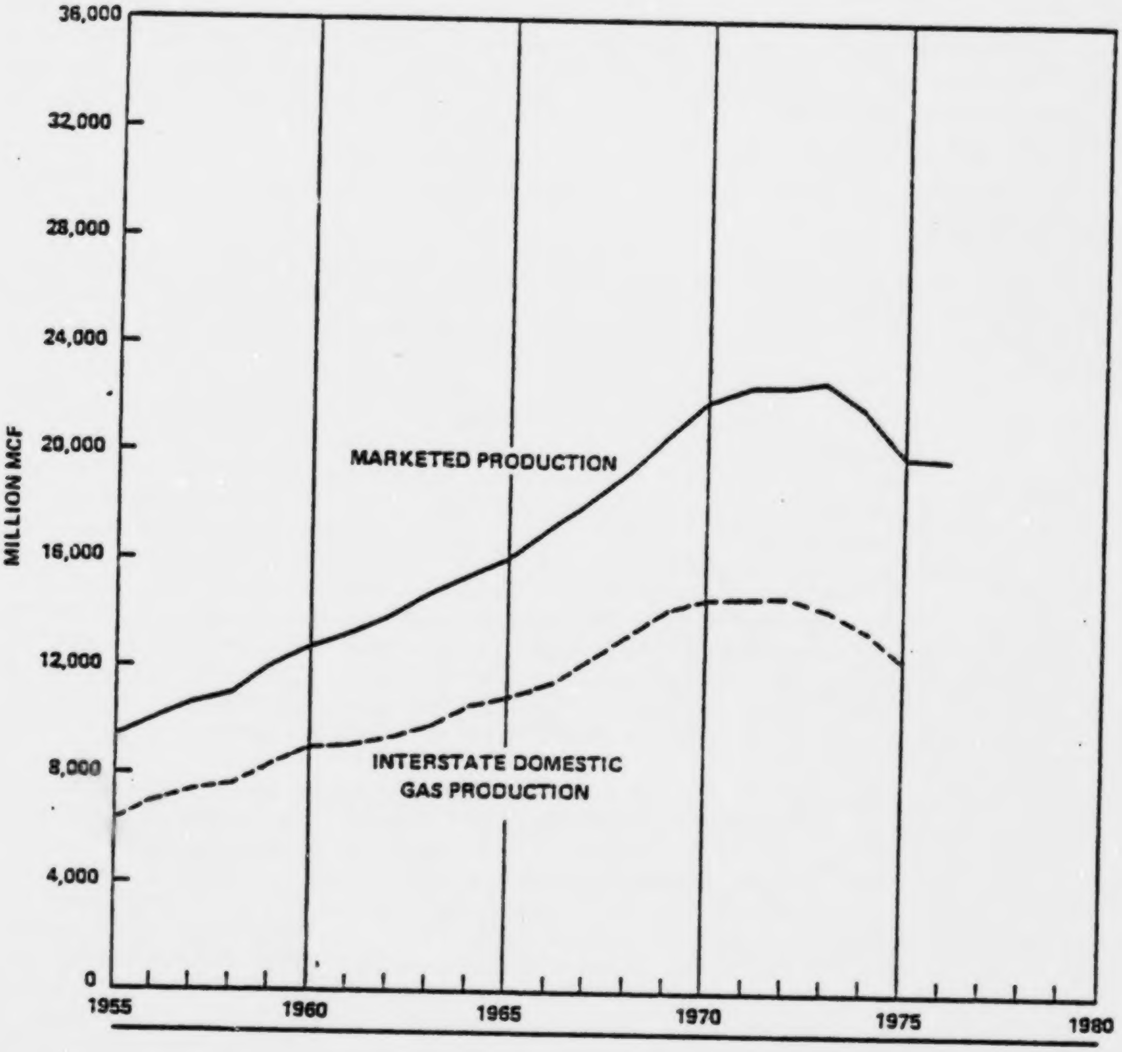
TABLE 1

DOMESTIC GAS PROCESSING CAPACITIES BY STATE
AS OF JANUARY 1, 1977 (3)

		Mcfd		Production - 1,000 gal/day (Average based on the past 12 months)								
State	No. plants	Gas capacity	Gas through-put	Ethane	Propane	Isobutane	Normal or unsplit butane	LP-Gas mix	raw NGL mix	Debut.nat gaso.	Other	Total products
Alabama	3	37.5	29.0		9.3		14.3		48.0	8.3		79.9
Alaska	2	60.0	44.9		10.5			78.0	27.0			115.5
Akansas	3	168.0	89.4		15.0	4.5	6.0		80.0	7.0	2.0	114.5
California	40	1,427.0	553.9		341.4	25.8	111.7	54.1	353.7	168.4	33.1	1,188.2
Colorado	24	767.5	509.9	34.1	180.6		92.4	503.2	318.1	91.4		1,219.8
Florida	2	722.5	630.0	391.8	362.9		202.4		25.5	113.6		1,096.2
Illinois	1	550.0	411.0	482.9	247.2	48.7	110.2			25.5		914.5
Kansas	29	5,520.5	4,369.9	420.0	1,017.9	116.6	334.7	39.5	1,012.8	300.0	1.1	3,242.6
Kentucky	2	895.0	669.8	107.0	34.0		22.0			30.0	244.0	437.0
Louisiana	108	23,576.8	16,439.4	1,434.3	1,981.2	446.0	698.5	751.6	8,438.5	854.0	1,184.4	15,788.5
Michigan	8	602.3	335.4		57.4	2.2	0.7	33.4	622.2	2.9	40.5	759.3
Mississippi	8	852.7	364.2		34.2		28.2	8.0	31.0	23.3	6.0	130.7
Montana	8	56.3	28.5		30.3		9.6	24.0	16.0	22.6		102.5
Nebraska	2	23.0	7.8		10.6		5.6			7.8		24.0
New Mexico	35	3,513.1	2,927.1	65.3	497.4	22.5	211.3	19.0	4,044.4	128.8	190.3	5,179.0
North Dakota	4	137.0	85.3		93.9		58.5		1.5	43.5		197.4
Oklahoma	82	4,209.8	2,990.4	82.7	853.3	118.3	278.7	648.4	2,689.4	283.3	565.5	5,519.6
Pennsylvania	2	5.0	3.2		2.4		1.1			1.5		5.0
South Dakota	1	38.0	12.0		7.0			7.7				14.7
Texas	352	27,469.1	17,136.5	4,359.5	5,846.7	803.8	2,368.0	689.5	13,509.0	2,845.7	2,566.7	32,988.9
Utah	8	313.5	142.9		123.4		58.4	6.0	130.4	58.5		376.7
West Virginia	4	368.0	242.4	175.4	107.6	18.3	34.3		349.0	34.5		719.1
Wyoming	35	1,297.5	779.5		356.6	1.7	151.6	168.0	622.4	128.3	13.1	1,441.7
Total	763	72,610.1	48,802.4	7,553.0	12,220.8	1,608.4	4,798.2	3,030.4	32,318.9	5,178.9	4,846.7	71,555.3

Since this compilation includes cycling plants reprocessing pipeline gas, totals shown here for gas throughput do not relate directly to government data on total gas processed, or sold. Similarly, liquids production figures are based on yearly average and do not necessarily reconcile with government data.

Conversion factor: 1000 gal/day x 0.0038 = kcum/day
Mcfd x 0.028 = Mcumpd



Conversion factor: Million mcf x 0.028 = MMcum

Figure 2: Total U.S. marketed production of natural gas and interstate domestic gas production 1955-1976.(2)

Propane production should be 87,500 cumpd (550,000 bpd), butane 33,400 cumpd (210,000 bpd), and isobutane 22,300 cumpd (140,000 bpd). This represents a 4% decline from 1976 production with most of this loss attributable to the declining availability of natural gasoline and heavier products. Table 2 shows the supply and disposition of domestic gas from 1955-1976. Table 3 shows the latest available information for total NGL production at domestic natural gas processing plants. In 1976, the processing of natural gas also yielded 19.6 Mcum (699 mcf) of helium and 1.2×10^6 metric tons of elemental sulfur. Figure 3 shows an overall material balance for the natural gas processing industry for 1976.

A list of conversion factors for English and SI metric units is provided in Appendix B.

Plant size and processing methods vary as a function of gas field size and the characteristics of the raw gas. Table 4 shows a breakdown of production for various plant size categories based on arbitrarily-chosen size designations.

Unit operations in natural gas processing plants are selected to fulfill intended market needs based on characteristics of the raw natural gas to be processed. Processing methods include absorption, refrigerated absorption, refrigeration, compression, absorption, cryogenic, and turbo-expansion. Refrigerated absorption is the leader in gas liquids recovery. Cryogenic and turbo-expander plants have dominated new plant construction since the 1960's. Cryogenic processing became economically feasible when the Federal Government initiated a helium storage program for national defense which has been recently discontinued. Turbo-expansion processing was introduced in 1964 and is now the dominant processing method employed in the United States.(4) Ninety-five percent of gas sweetening is done by the several amine processes. The Claus process is used most widely for sulfur recovery from acid gases.

There are approximately 12,000 gas producers in the United States. However, in 1964, 34 companies accounted for 96% of the interstate volume. Eighteen of the top 20 gas producers are owned by oil companies. Exxon Corporation is the largest domestic producer and pipelines approximately 20% of the domestic gas supply. The 25 largest pipeline companies handled 95% of all interstate gas shipments.(6) Many interstate pipelines have also become major gas producers. The two largest pipelines have also become major gas producers. The two largest pipeline companies in 1975 were El Paso Natural Gas Company and the Tennessee Gas Pipeline Company. Their production volumes (1975) were 34 Gcum (1.223 tcf) and 33.9 Gcum (1.211 tcf), respectively. El Paso Natural Gas Company was the ninth largest of all producers in 1973. A tabulation of the major gas supply companies, their annual productions and reserves with gross exchanges, from 31 December 1970 to 31 December 1975, is included in Appendix C. Independent gas producers, those not associated with pipeline companies, are usually under longterm contracts to supply specified quantities at fixed prices to the pipeline companies. Seventy-five percent of the domestic processing plants are owned by producers, with the balance owned by pipeline companies.

TABLE 2

SUPPLY AND DISPOSITION OF GAS IN THE UNITED STATES, 1955 - 1976 (2)

(Millions of cubic feet) *

Year	Gross Production[a]			Disposition of Gross Production									
	Gas Wells	Oil Wells	Total	Repressuring	Vented and Flared	Marketed Production[b]	Extraction Loss	Lease and Plant Fuel	Net Change in Underground Storage	Pipeline Fuel	Unaccounted For	Net Imports	Delivered to Consumers[c]
1955	7,841,958	3,877,836	11,719,794	1,540,804	773,639	9,405,351	1,507,671		67,934	245,246	246,933	(20,141)	7,317,426
1956	8,306,550	4,066,355	12,372,905	1,426,648	864,334	10,081,923	1,420,550		136,470	295,972	212,992	(25,583)	7,990,356
1957	8,716,835	4,189,834	12,906,669	1,417,263	809,148	10,680,256	1,479,720		191,396	299,235	205,373	(3,714)	8,500,820
1958	9,154,051	3,992,584	13,146,635	1,482,975	633,412	11,030,248	1,604,104		83,081	312,221	283,597	97,078	8,844,323
1959	10,101,754	4,127,518	14,229,272	1,612,109	571,048	12,046,115	1,737,402		118,742	349,348	223,312	115,577	9,732,888
1960	10,853,426	4,234,485	15,087,911	1,753,996	562,877	12,771,038	1,779,671		131,694	347,075	274,231	144,314	10,382,681
1961	11,195,087	4,265,225	15,460,312	1,682,754	523,533	13,254,025	1,881,208		145,616	377,607	234,808	208,113	10,822,899
1962	11,702,382	4,336,591	16,038,973	1,736,722	425,629	13,876,622	1,993,128		86,487	382,496	285,726	385,720	11,514,505
1963	12,606,022	4,367,346	16,973,368	1,843,297	383,408	14,746,663	2,081,339		130,772	423,783	364,658	389,247	12,135,358
1964	13,035,200	4,405,100	17,440,300	1,638,161	339,996	15,462,143	2,082,029		128,804	433,204	302,781	421,421	12,936,746
1965	13,523,600	4,439,500	17,963,100	1,604,204	319,143	16,039,753	1,909,697		118,115	500,524	318,711	430,262	13,622,968
1966	13,893,921	5,139,918	19,033,839	1,451,516	375,695	17,206,628	1,772,708		68,855	535,353	401,203	455,141	14,883,650
1967	15,346,853	4,904,923	20,251,776	1,590,574	489,877	18,171,325	784,534	1,140,966	184,829	575,752	296,214	482,612	15,671,642
1968	16,539,925	4,785,075	21,325,000	1,486,092	516,508	19,322,400	827,877	1,237,131	95,539	590,965	325,062	558,140	16,803,966
1969	17,489,415	5,189,750	22,679,195	1,455,205	525,750	20,698,240	866,560	1,345,648	119,500	630,962	331,587	675,647	18,079,630
1970	18,544,658	5,191,795	23,786,453	1,376,351	489,460	21,920,642	906,413	1,398,758	398,160	722,166	227,650	750,967	19,018,462
1971	18,925,136	5,162,895	24,088,031	1,310,458	284,561	22,493,012	883,127	1,413,650	331,768	742,592	338,999	854,336	19,637,212
1972	19,042,592	4,973,517	24,016,109	1,236,292	248,119	22,531,698	907,993	1,455,563	135,734	766,156	328,002	941,483	19,879,733
1973	19,371,600	4,695,602	24,067,202	1,171,361	248,292	22,647,549	916,551	1,495,915	441,504	728,177	195,863	955,732	19,825,271
1974	18,669,212	4,180,581	22,849,793	1,079,890	169,381	21,600,522	887,490	1,477,386	83,663	668,792	288,731	(882,495)	19,076,955
1975	17,380,293	3,723,237	21,103,530	860,956	133,913	20,108,661	872,282	1,396,277	344,054	582,963	235,068	880,333	17,558,353
1976	17,190,655	3,753,123	20,943,778	859,410	131,930	19,952,438	860,000[d]	1,380,000[d]	(100,000)[d]	600,000[d]	230,000[d]	899,058	17,881,496[d]

a. Includes gas (mostly residue gas) blown to the air but does not include direct waste on producing properties, except where data are available.
b. "Marketed Production" equals "Total Gross Production" less "Repressuring" and "Vented and Flared". It includes an allowance for natural gas liquids content in the natural gas.
c. Includes net imports, but excludes Substitute Natural Gas.
d. Data not available at time of publication. Estimated by A.G.A.
Sources: U.S. Bureau of Mines, *Natural Gas, Annual.*

*Conversion factor: mcf x 0.028 = Mcum

TABLE 3

PRODUCTION AT DOMESTIC NATURAL GAS PROCESSING PLANTS FOR APRIL, 1977 (5)

Product	Throughput		Stocks	
	cu.m	(1000 barrel)	cu.m	(1000 barrel)
Ethane	1925	(12,119)	2060	(12,964)
Propane	2490	(15,707)	8555	(53,886)
Isobutane	390	(2,471)	900	(5,664)
N Butane	700	(4,429)	2165	(13,640)
Other Butanes	370	(2,333)	235	(1,480)
Butane-Propane Mix	30	(199)	155	(984)
Total	5905	(37,258)	14070	(88,618)
Natural Gasoline & Isopentane	1810	(11,407)	960	(6,051)
Plant Condensate	175	(1,111)	60	(383)
Other Products	20	(140)	15	(92)
Total	7910	(49,916)	15105	(95,144)

OVERALL MATERIAL BALANCE FOR NATURAL GAS PRODUCTION - 1976

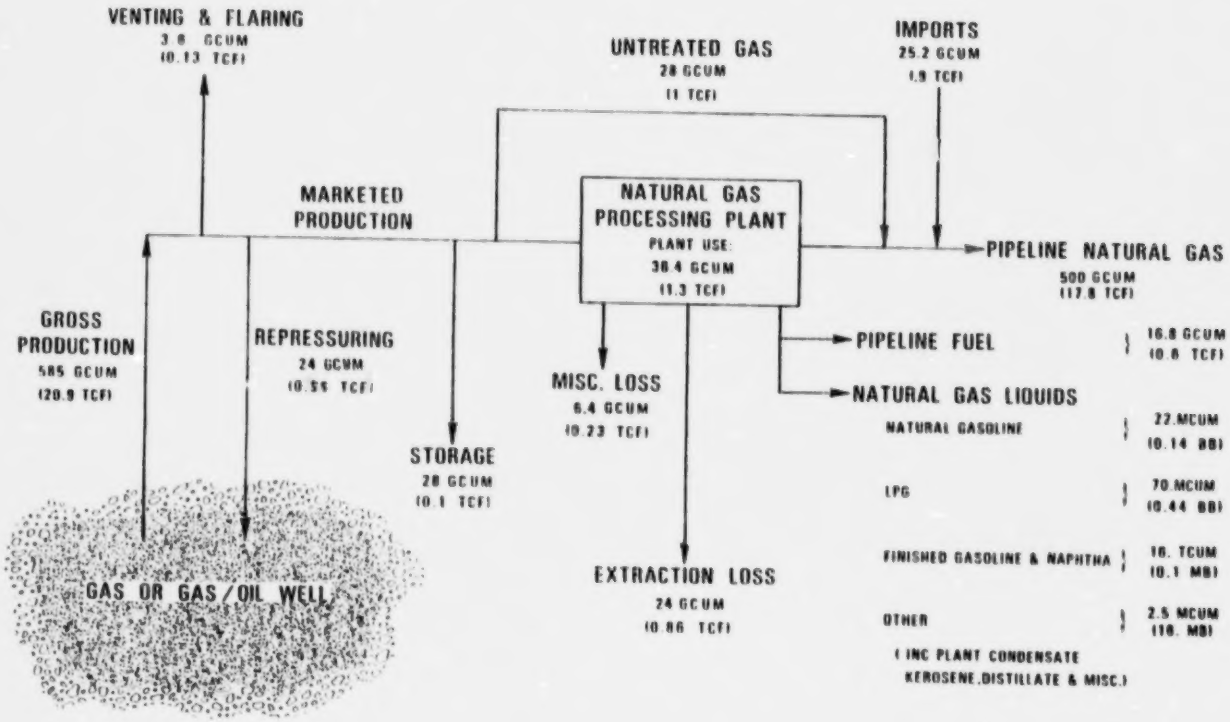

VENTING & FLARING
3.8 GCUM
(0.13 TCF)
UNTREATED GAS
28 GCUM
(1 TCF)
IMPORTS
25.2 GCUM
(.9 TCF)
MARKETED PRODUCTION
NATURAL GAS PROCESSING PLANT
PLANT USE:
38.4 GCUM
(1.3 TCF)
PIPELINE NATURAL GAS
500 GCUM
(17.8 TCF)
GROSS PRODUCTION
585 GCUM
(20.9 TCF)
REPRESSURING
24 GCUM
(0.85 TCF)
PIPELINE FUEL
16.8 GCUM
(0.6 TCF)
MISC. LOSS
6.4 GCUM
(0.23 TCF)
NATURAL GAS LIQUIDS
NATURAL GASOLINE
22.MCUM
(0.14 BB)
STORAGE
28 GCUM
(0.1 TCF)
LPG
70.MCUM
(0.44 BB)
FINISHED GASOLINE & NAPHTHA
16. TCUM
(0.1 MB)
EXTRACTION LOSS
24 GCUM
(0.86 TCF)
GAS OR GAS/OIL WELL
OTHER
2.5 MCUM
(16. MB)
(INC PLANT CONDENSATE
KEROSENE,DISTILLATE & MISC.)

Figure 3: Overall material balance for natural gas production - 1976.

TABLE 4

OVERALL SIZE AND CAPACITY OF THE NATURAL GAS PROCESSING INDUSTRY, 1976 (2)

Size Designation	Production Capacity Mcumpd (mcfd)	Number of Plants	Volume Produced Gcum (tcf)	Percent of Total Production
Small	≤ 0.3 (.5 to 9)	225	10 (.36)	2
Medium	0.3 to 1.13 (9.1 to 40)	268	90 (3.2)	18
Large	>1.13 (40.1 & up)	270	400 (14.2)	80
TOTAL		763	500 (17.8)	100

The gas processing industry employs approximately 15,000 people. Based on the present salary-income structure, the industry pays an average of $6.59 per hour, thus providing $197.7 million in direct income.(6) Capital investment within the industry is shown in Table 5.

As shown in this table, capital investment has been increasing sharply while the number of plants has been decreasing. Higher demand and decreasing supplies have influenced the industry to maximize efficiency and improve product recovery. The total value of NGL production in 1975, 95 Mcum (596 million barrels), is estimated at $2.8 billion. Natural gas liquids production for 1976, 93 Mcum (587 million barrels), generated approximately $3.3 billion in revenues (see Table 6). Pipeline natural gas yielded revenues of $23.7 billion in 1976 from total shipments of 557 Gcum (19.9 tcf).

Revenues from helium and sulfur production (1974) were $18 million and $36 million, respectively.

Several factors are influencing the future disposition of the natural gas industry. As shown in Appendix C, the reserves of the major pipelines are declining and additions to reserves are small. Figure 4 shows the history of proven reserves and additions and the gross production of the industry. These data show a decline of approximately 6% from 1975 to 1976 to approximately 6 Tcum (216 tcf).

A graph of interstate domestic gas production is shown in Figure 5. The 1976 production was 339 Gcum (12.1 tcf), while 1975 production was 344 Gcum (12.3 tcf), 1.4% higher. This trend is likely to continue since the volume of reserves dedicated to interstate pipelines has been declining since 1967 (see Figure 4). The overall marketed production of natural gas and NGL declined only 0.8%, from 591 Gcum (21.1 tcf (1973)) to 557 Gcum (19.9 tcf (1976)).

Figure 6 shows the projected isobutane supply and demand for total NGL, as well as for propane and butane, through 1986. These data show a decline from the 1976 domestic production of NGL to 77 Mcumpy (485 million barrels per year) by 1980. Ethane production has been expanding as demand for its use as the preferred feedstock for ethylene synthesis has increased substantially in recent years.

Twenty-five new plants are either under construction or in the planning stages (see Table 7). These plants are replacing old facilities, additions to capacity at existing fields, or part of new field development. Their construction represents a major portion of the estimated $5 billion required by the industry for capital outlay by 1986.(7) Of course, substantial new discoveries in the Outer Continental Shelf (OCS) off the East Coast, California, Alaska, and the Gulf Coast would have a great effect on the industry's capital outlay, as well as on the supply-demand picture.

TABLE 5

CAPITAL INVESTMENT IN THE NATURAL GAS PROCESSING INDUSTRY (7)

Year	Millions of Dollars Expended
1972	175
1973	150
1974	225
1975	325

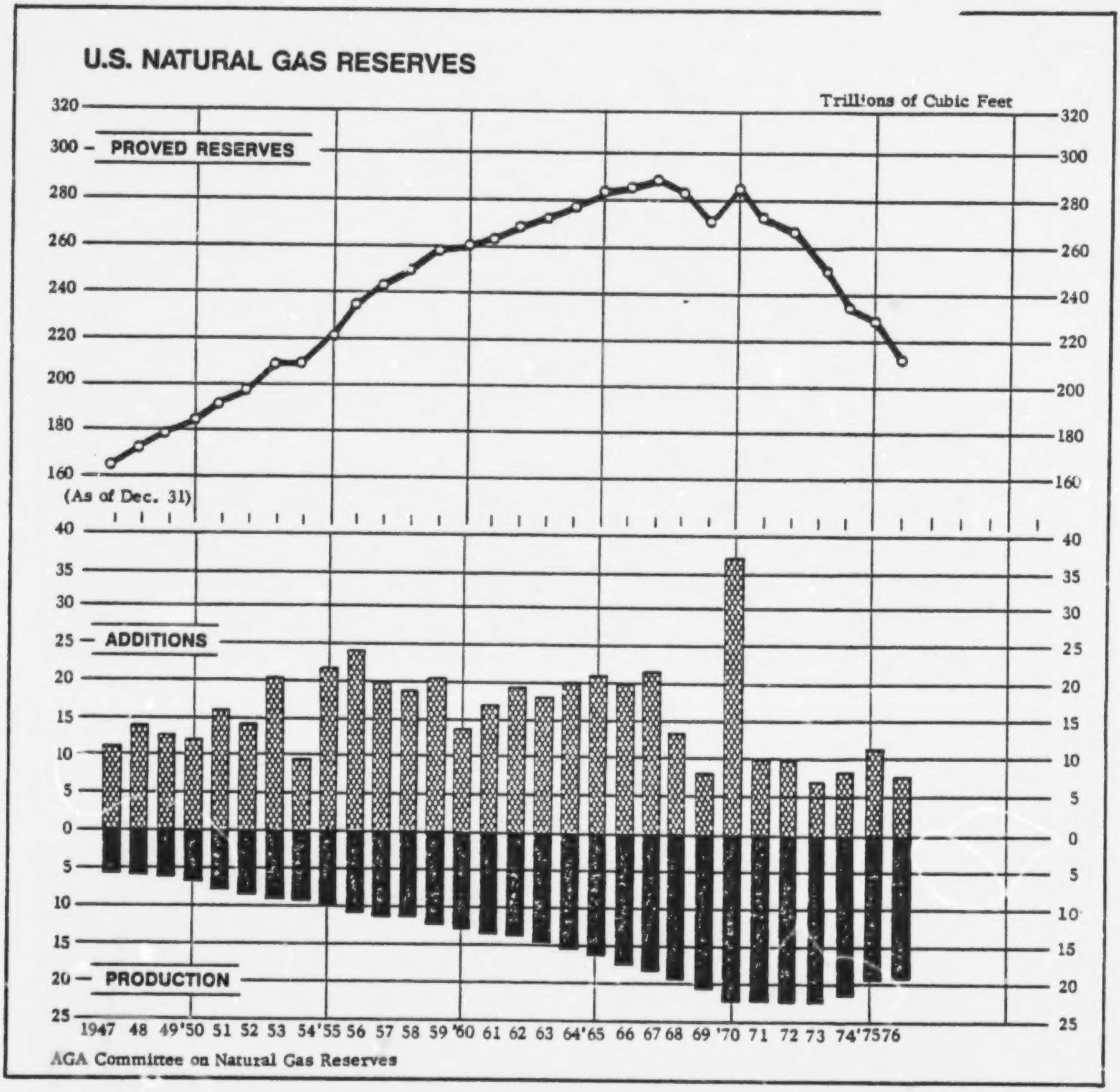
TABLE 6

NATURAL GAS TREATED FOR NATURAL GASOLINE AND ALLIED PRODUCTS, AND QUANTITIES AND VALUE OF PRODUCTS RECOVERED, 1955-1976 (2)

	Natural Gas Treated	Products Recovered							
		Natural Gasoline		Liquefied Petroleum Gases		Finished Gasoline and Naphtha		Other Products[a]	
Year	(Millions of cubic feet)	Quantity (Thousands of gallons)	Value (Thousands of dollars)	Quantity (Thousands of gallons)	Value (Thousands of dollars)	Quantity (Thousands of gallons)	Value (Thousands of dollars)	Quantity (Thousands of gallons)	Value (Thousands of dollars)
1955	8,185,953	4,457,079	$313,075	5,972,698	$195,231	823,103	$72,192	564,722	$38,508
1956	8,445,009	4,438,890	316,646	6,487,413	265,185	832,915	75,102	535,295	40,210
1957	8,578,561	4,499,495	305,937	6,655,282	263,665	779,807	72,154	455,005	37,700
1958	8,452,544	4,355,025	300,666	6,783,000	296,571	701,456	53,401	539,977	39,072
1959	9,186,862	4,222,266	290,311	7,874,706	349,802	660,666	56,517	714,170	61,866
1960	9,768,189	4,479,454	313,058	8,444,074	391,566	503,659	43,400	859,394	60,361
1961	10,261,669	4,666,319	311,966	9,085,465	370,186	473,496	31,996	965,648	68,057
1962	11,089,241	4,772,260	333,965	9,409,083	353,334	450,991	37,347	1,021,271	73,505
1963	12,430,353	4,899,323	320,131	10,302,250	359,770	499,901	40,922	1,135,743	78,120
1964	13,176,126	5,286,703	341,714	10,743,591	362,792	506,505	37,815	1,206,973	84,071
1965	13,772,101	5,457,367	360,603	11,257,267	417,249	439,267	36,270	1,391,436	97,481
1966	14,924,429	5,564,139	366,332	12,134,294	[illegible]27,223	380,135	33,180	1,604,154	120,426
1967	15,641,633	5,850,271	389,156	13,717,861	632,994	307,263	28,044	1,731,727	129,742
1968	16,316,674	6,210,708	411,695	14,753,004	552,335	280,728	26,577	1,868,622	133,407
1969	17,655,108	6,633,018	457,986	15,895,194	498,927	374,514	36,954	1,467,396	108,144
1970	18,509,309	6,935,835	468,602	16,783,662	672,088	240,702	23,234	1,488,270	111,188
1971	19,252,807	6,942,474	496,676	17,540,628	769,397	224,784	23,210	1,240,344	96,771
1972	19,906,893	6,875,442	500,425	18,678,912	828,718	186,732	20,737	1,063,986	83,261
1973	19,679,291	6,791,736	568,214	18,775,386	1,188,289	136,038	13,902	942,606	86,668
1974	18,684,480	6,212,766	974,825	18,813,732	1,960,769	52,878	10,028	797,664	122,305
1975	17,748,426	5,620,608	777,637	18,651,612	1,893,890	45,528	8,411	712,488	92,650
1976P	b	5,575,584	882,718	18,369,372	2,298,647	40,572	9,650	670,362	93,074

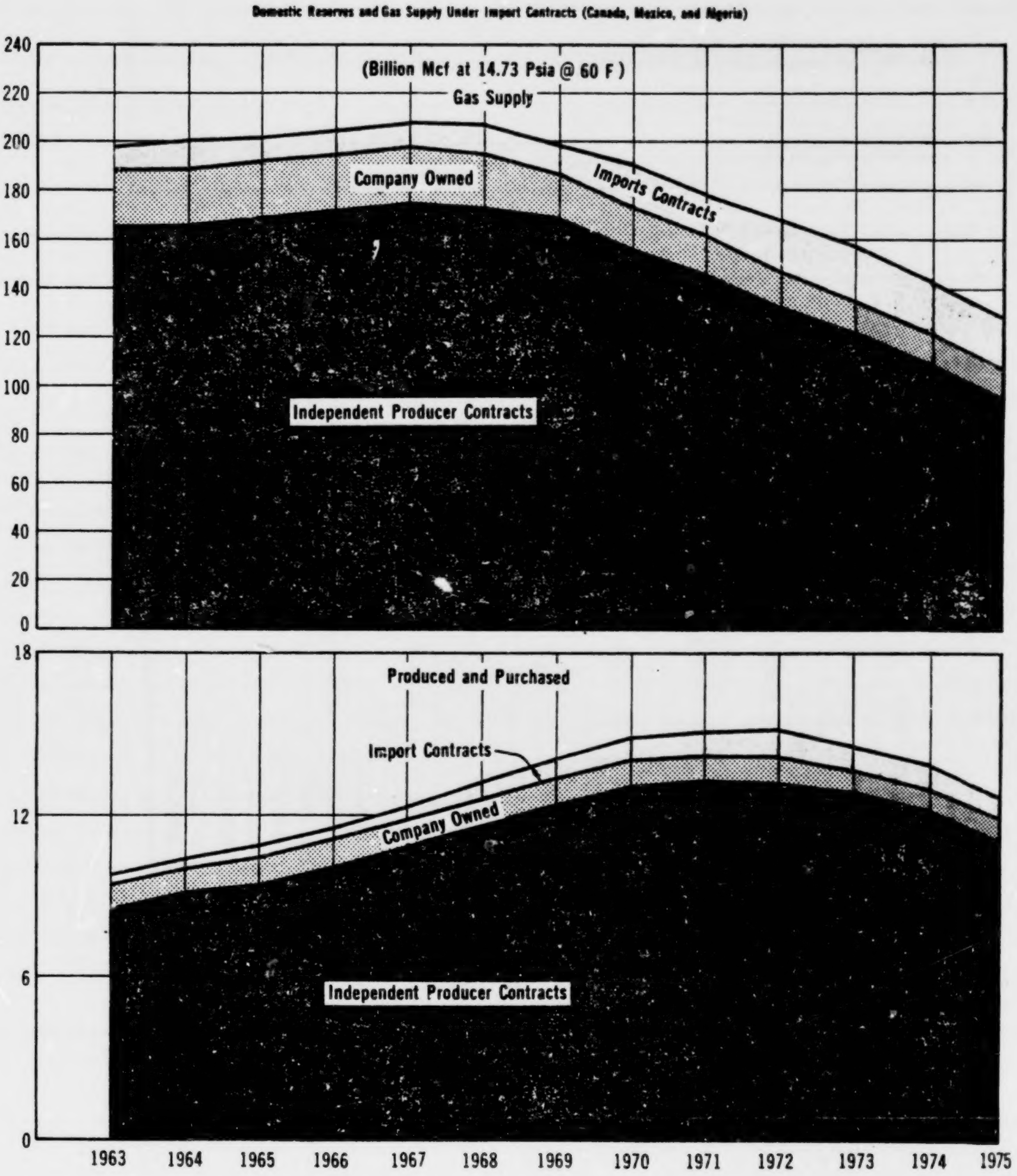
a. Includes plant condensate, kerosene, distillate fuel oil, and miscellaneous products.
b. Not available.
p—Preliminary.
Source: U.S. Bureau of Mines.

Conversion factor: 1000 gal x 0.0038 = kcum



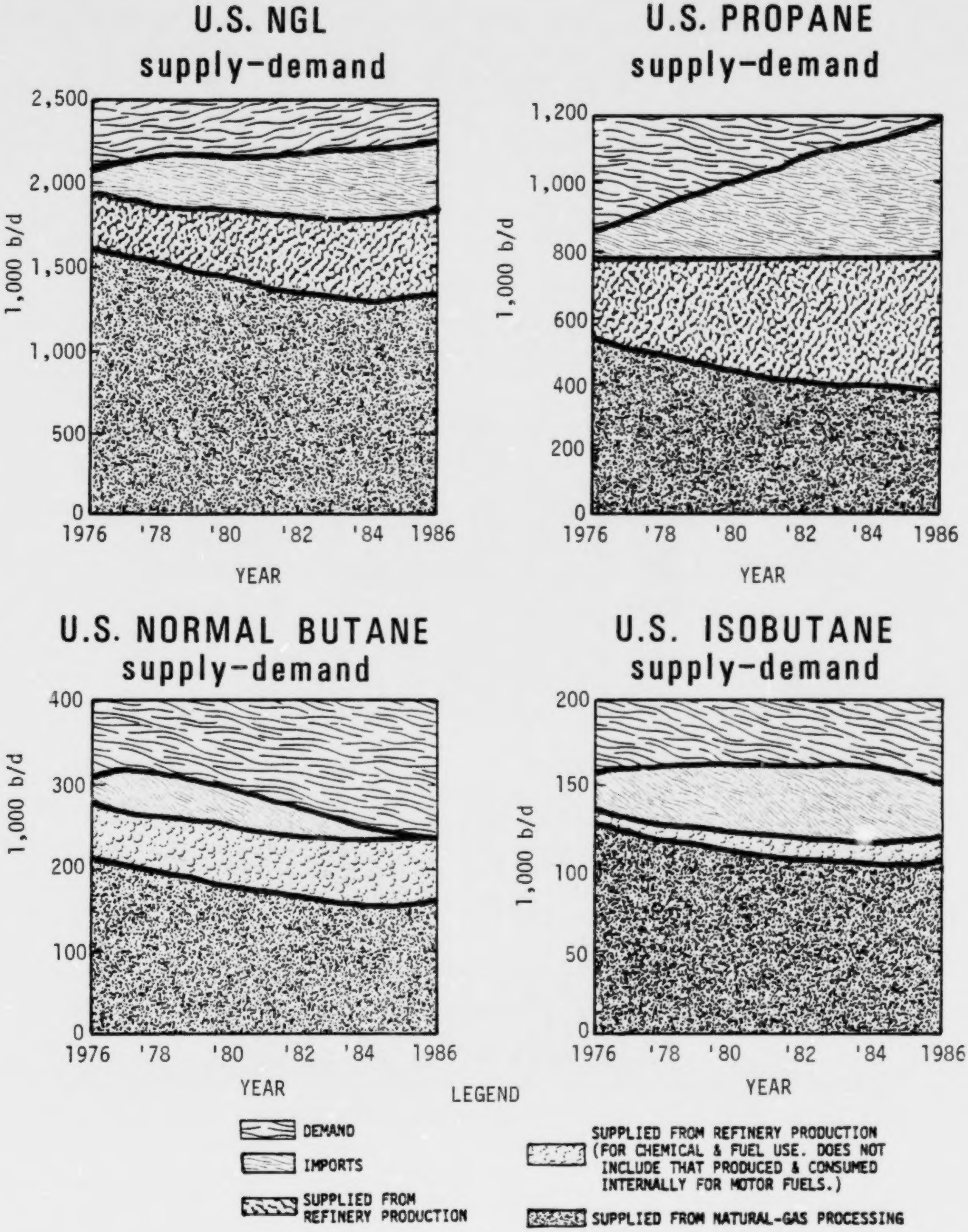
Conversion factor: trillion cu ft x .028 = Tcum

Figure 4: Graph of U. S. natural gas reserves.(2)



Conversion factor: Billion Mcf x 0.0028 = Gcum

Figure 5: History of total interstate gas supply. (8)



Conversion factor: 1000 b/d x 0.159 = kcum/d.

Figure 6: Graphs of supply and demand for various NGL products.(4)

TABLE 7

PLANNED CONSTRUCTION OF DOMESTIC NATURAL GAS PROCESSING PLANTS AS OF JANUARY 1, 1977 (3)

***AMINOIL USA INC. Lucien, Okla.** 16.0 MMcfd by expander process (old plant to be shut down) 44,800 g/d raw natural gas liquids mix. Engineering stage. Contractor: Worley. Completion: July 1977.

ATLANTIC RICHFIELD CO. Crittendon plant, Winkler County, Tex. 35 MMcfd expansion. 58,000 gal/d raw natural gas liquids mix under construction. Contractor: Dresser. Cryogenic turbo-expander process. $4.8 MM.

BP ALASKA INC. North Pole. 83,000 b/d dehydrators (six each) in engineering stage. Eng: Howe-Baker. Contractor: Brown & Root.

***CHEVRON USA INC. Pointe Coupee, Parish, La.** 100 MMcfd. Iron sponge process. Completion: May 1977.

***CITIES SERVICE CO. Hutchinson, Kan.** 44,000 b/d de-ethanizer system. Engineering stage. Contractor: Dresser.

***CONSUMERS POWER CO. Jackson, Mich.** 1.5 MMscfd each of three field compressors. Proposed. Completion: December 1977.

***EXXON CO. Arcadia Parish, La.** 950 MMcfd Blue Water plant. Contractor: Fish Eng. Completion: late 1978.

Crane County, Tex. 65 MMcfd replacement of processing facilities at Sand Hills plant. Completion: late 1978.

***GENERAL CRUDE OIL CO. Salt Creek, Kent County, Tex.** 30,000 g/d demethanizer. Refrigeration process. Planned. Contractor: Ortloff.

***GETTY OIL CO. Hatter's Pond, Mobile County, Ala.** 50 MMcfd expansion. 72,000 g/d propane, 51,800 g/d butane 15,500 g/d debutanized natural gasoline. Refrigeration method. Engineering stage. Contractor: Delta. Completion: June 1978.

***HOUSTON OIL AND MINERAL CORP. Texas City, Tex.** 400 MMcfd by cryogenic turboexpander method. 105,000 g/d ethane, propane, butanes+. Planned. Completion: Oct. 1978.

***MOBIL OIL CORP. Vermilion Parish, La.** 150 MMcfd plant planned. Design stage.

Coyanosa, Pecos County, Tex. 125 MMcfd expansion. Cryogenic process. Contractor: Trend. Completion: June 1977.

Midland County, Tex. 90 MMcfd expansion. Cryogenic process. Contractor: Dresser. Completion: June 1977.

NORTHERN NATURAL GAS. Ventura, La. 10 MMscfd LNG unit under construction. Contractor: J. F. Pritchard. Completion: 1977.

***NORTH TEXAS LPG CORP. South Galveston.** Proposed plant. Cryogenic process. Status: Cost-benefit analysis.

PHILLIPS PETROLEUM CO. Crane County, Tex. 20 MMcfd natural gas liquids expander plant. Contractor: Tulsa Pro-Quip. Completion: May 1977.

Kingfisher County, Okla. 75 MMcfd natural gas liquids expander plant. Contractor: Dresser. Completion: July 1977.

Sherman plant, Hansford County, Tex. 75 MMcfd natural gas liquids expander plant. Staff will build. Completion: May 1978.

Spraberry plant, Glasscock County, Tex. 25 MMcfd natural gas liquids expander plant. Completion: July 1977.

***PLACID OIL CO. Patterson Plant 2, St. Mary Parish, La.** 600 MMcfd by turboexpander method 610,000 g/d products. Under construction. Contractor: Delta Eng. Completion: July 1977.

SHELL OIL CO. Kalkaska, Mich. 100 MMcfd expansion. 180,00 g/d demethanized gasoline. Additional ethane recovery (parallel existing process). Turboexpander process. Contractor: Hudson. Completion: November 1977.

SKELLY OIL CO. Eunice, New Mexico. 140 MMcfd expansion under construction. Contractor: Randall.

***TUCO INC. Hobbs, N.M.** 75 MMcfd by expander method. 125,000 g/d demethanized product. Contractor: Randall. Completion: Sept. 1977.

U.S. NAVY. Elk Hills, Calif. 100 MMscfd plant. Engineering stage. Contractor: Ameron Process. Completion: Dec. 1977.

SECTION 4

PRESENT ENVIRONMENTAL REGULATIONS AFFECTING THE NATURAL GAS PROCESSING INDUSTRY

The natural gas processing industry is subject to federal, state, and local regulations which control by permit its air, water and solid waste impacts on the environment.

The primary air pollutants associated with gas processing include sulfur dioxide (SO_2), hydrogen sulfide (H_2S) and hydrocarbons. Cooling water blowdown and water extracted from the wells (produced water) are the primary sources of water pollution for the industry. Blowdown from cooling water usually contains treatment chemicals such as chromates and/or other metals and high dissolved solids. Produced water, often a brine liquid, has a very high content of mineral salts.

Solid waste from natural gas processing plants usually consists of spent absorbents. Noise and odor problems are incidental and generally do not affect the community.

FEDERAL REGULATIONS

Air Pollution

There are no New Source Performance Standards (NSPS) for the natural gas processing industry at this time. However, sulfur dioxide and hydrocarbons, the principal pollutants for the industry, are criteria pollutants. As such, their emission is controlled via State Implementation Plans (SIP's) devised to enable each state to meet the national air quality standards by July, 1975.

The Clean Air Act Amendments of 1977 will require substantial revision to the SIP's to address the prevention of significant deterioration in attainment areas and reduction of emissions from stationary sources in non-attainment areas. The industry may thus be affected in the future by regulations developed in response to these Amendments.

Water Pollution

There are several different means by which the Federal government may effect point source water pollution. The Federal Water Pollution Control Act has provisions for:

1. Technology-based effluent guidelines

2. Water quality standards

3. Limitations on toxic substances

4. Control and prevention of oil spills.

Federal technology-based effluent guidelines have not been promulgated for the natural gas processing industry. However, states are free to impose effluent limitations on a case-by-case basis. The Federal Water Pollution Control Act (FWPCA) also dictates that states develop water quality standards and implementation plans to achieve these goals. This is one of the primary means by which the industry is affected by Federal regulations.

Section 311 of the FWPCA is written to encourage the prevention of spills, leaks and other nonroutine discharges of oils and hazardous materials. These regulations have undergone significant modification and will be promulgated in the near future. At present, spill prevention control and countermeasure (SPCC) plans are required if a potential spill could affect a navigable waterway.

The issue of deep well injection of produced water and the intent of the FWPCA has not been established at this time. EPA's direct authority has been challenged successfully although states are required to regulate subsurface disposal before being granted NPDES permitting authority.

Part C of the Safe Drinking Water Act also deals with the protection of underground sources of drinking water. Regulations wil be promulgated in the near future with primary enforcement responsibility assigned to the states. These regulations will include a specific prohibition of interference with injections of brine, etc. in connection with oil and natural gas production unless such requirements are essential to protect underground supplies of drinking water.

The single toxic substance associated with this industry at present is chromium which is used as a corrosion inhibitor in cooling water.

The newly-enacted Toxic Substance Control Act (TSCA) imposes new requirements on manufacturers and processors of chemical substances and mixtures. Although this law is still in its initial implementation phase, it is quite possible that natural gas processors will be treated as manufacturers or processors of chemical substances. If so, the industry will become subject to TSCA's reporting and testing requirements as well as any general requirements of EPA with respect to chemicals posing an unreasonable risk to public health or the environment.

Federal involvement in solid waste disposal has been greatly expanded with the enactment of the Resource Conservation and Recovery Act (RCRA) of 1976. This Act provides for Federal standards for transport and disposal of hazardous and other solid waste. States may be granted authority by EPA by initiating programs comparable to the Federal solid waste management guidelines.

The FWPCA establishes an elaborate permit system (NPDES) to insure that the substantive requirements of the statutes are fulfilled. Authority for permit issuance lies with EPA. However, EPA may delegate its authority to states which have adopted acceptable programs. Where states issue NPDES permits, EPA serves in an oversight capacity and can block permit issuance. Permits are issued by EPA for Texas which has 46% of the natural gas processing plants and Louisiana with 14% of the total.

STATE REGULATIONS - LOUISIANA

Water Pollution Control

The Louisiana Stream Control Commission, chaired by the Director, Louisiana Wild Life and Fisheries Commission, is the water quality control authority for the State. Other members of the Commission are the heads of the following State agencies, or their designated representatives:

1. President, Louisiana Board of Health
2. Commissioner, Department of Conservation
3. Attorney General
4. Commissioner, Department of Agriculture and Immigration
5. Executive Director, Department of Commerce and Industry
6. Director, Department of Public Works

The Division of Water Pollution Control under the Louisiana Wild Life and Fisheries Commission, serves as the research, investigative, and enforcement group for both the Stream Control Commission and the Wild Life and Fisheries Commission in matters pertaining to water quality and pollution (Source: Acts 1940, No. 367; Acts 1942, No. 199; Acts 1948, No. 87; Acts 1952, No. 254; Acts 1970, No. 405, No. 628; as listed under Title 56).

The Louisiana Stream Control Commission is authorized to make the "certifications" which applicants for Federal permits are required to provide to the appropriate Federal agencies (i.e., Environmental Protection Agency, U. S. Coast Guard--Oil Transfer Facilities, etc.) under the Federal Water Pollution Control Act, Section 21 (Source: Acts 1970, No. 628, Section 1).

Eight rules are set forth in the Louisiana regulations which relate to water pollution from oil and gas operations:

Rule No. 1.

Waste oil, oil sludge, etc. shall be destroyed on the lease where the wastes originate by burning (smoke prohibited by the Louisiana Air Control Board rules) or otherwise in a manner to eliminate any pollution hazard.

Rule No. 2.

No oil fluids permitted to flow on surface of the ground or allowed to flow into any stream, lake, or other body of water.

Rule No. 3.

Each land located producing well and pumps handling oily fluids shall be provided with a surrounding ditch and gathering sump. Each marine located pumping well shall be equipped with an impervious deck or catch tank installed around the wellhead. All workover and drilling barges shall have a keyway gate to retain oil or oily fluids. All workover, drilling, or power unit barges will be equipped with an oil combing drain system and catch tank.

Rule No. 4.

Each permanent oil tank or tank battery located within corporate limits, within 500 feet of a highway or inhabited dwelling, or closer than 1000 feet to a church or school must be surrounded by a dike (fire wall) capable of containing the total volume of the encompassed tanks. Tanks not falling into these categories must have a means to collect and contain spillage or leaks so as to prevent pollution of the surrounding area.

Rule No. 5.

Oil lines, oil barges, and oil transfer facilities will be operated at all times with full precaution and design considerations against spillage.

Rule No. 6.

Written approval is necessary for transferring unseparated salt water from a lease to a central treating facility. Oil field brines discharged to streams shall not have an oil content in excess of 30 ppm.

Rule No. 7.

No oil field brine shall be discharged into any body of water when it is determined by the Stream Control Commission that it would be detrimental.

Rule No. 8.

Whenever possible, disposition of oil field brine should be into disposal wells. Disposal wells shall be drilled, cased, cemented, equipped, and operated so that no fresh water horizon(s) shall be polluted.

Air Pollution Control

The Louisiana Air Control Law was enacted by the State Legislature as law by Act 259. The Air Control Law created the Louisiana Air Control Commission. The Louisiana Department of Health is authorized by the Air Control Commission to promulgate and administer regulations (R.S. 40:2204A).

Detailed regulations and the Louisiana Air Standards Implementation Plan became effective January 30, 1972, on submittal to the Federal Environmental Protection Agency (EPA). This Plan was approved by EPA on May 30, 1972, with certain exceptions. Necessary amendments and revisions were approved by EPA in August, 1972.

A certificate of approval is required (before construction begins) from the Louisiana Air Control Commission for all installations constructed after June 19, 1969 which might produce emissions. Emergency operation emissions shall be reported to the Air Control Commission without delay.

The Commission is authorized to prevent the construction or operation of sources if emissions would cause violation of the ambient standards. Standards currently exist for particulates, SO_2, CO, non-methane hydrocarbons, reactive hydrocarbons, and NO_x.

Outdoor burning of waste hydrocarbon products is allowed where it occurs from petroleum exploration development, production, or natural gas processing operations. Burning at the site of occurrence is permitted for such products as (but not limited to) basic sediments, liquid produced in well testing operations, paraffin, and hydrocarbons spilled from pipeline breaks or other failures. These burning operations are permitted where it is not practicable to recover and transport the waste products for sale or reclamation or to dispose of them lawfully in some other manner.

Except for imminent threat or injury to human life or significant property damage, outdoor burning shall be conducted under the following conditions:

a. The burning location shall not be within or adjacent to a city or town or in such proximity thereto that the ambient air is affected.

b. Burning operations allowed only between 8:00 a.m. and 5:00 p.m.

c. Burning shall be controlled so as not to create a traffic hazard.

Solid Waste

Louisiana has a comprehensive solid waste management which meets the requirements provided by RCRA. EPA has granted Louisiana interim authorization to carry out its program for two years from October 21, 1978 to October 21, 1980.

STATE REGULATIONS - TEXAS

Water Pollution Control

Although general water pollution control authority in Texas is vested in the newly-formed Department of Water Resources, the Texas Railroad Commission is solely responsible for the control and disposition of waste and the abatement and prevention of pollution of surface and subsurface water resulting from activities associated with the exploration, development, and production of oil and gas. The Texas Railroad Commission may issue permits for the discharge of waste resulting from these activities, and discharge of waste into any water in this State resulting from these activities shall meet the water quality standards established by the Texas Water Quality Board.

In applying the law that the Railroad Commission is responsible for matters "associated with the exploration, development, and production of oil or gas," the Texas Water Quality Board and the Railroad Commission have agreed that the Commission's responsibility includes gas processing and oil and gas transmission lines.

The basic regulatory provision of the Texas Railroad Commission with respect to water protection is Rule 8 which is outlined in Table 8.

Air Pollution Control

The Texas Clean Air Act was enacted to safeguard the air resources of the state from pollution. The Texas Air Control Board (TACB) was named as the principal authority concerning air quality and pollution control.

A comprehensive set of rules and regulations was adopted by the TACB on January 26, 1972, in an effort to implement Federal laws concerning air quality standards and implementation plans. Some rules required compliance effective March 5, 1972. Others required compliance by specified times with provisions that periodic progress reports be submitted.

Texas has eight substantive regulatory requirements governing air pollution. Regulation I refers to visible emissions and particulate matter. Regulations I, II, V and VI affect the natural gas industry.

Visible emissions from currently constructed stationary flues may not exceed 30 percent opacity averaged over a five-minute period. Flues constructed after January 31, 1972 may not cause emissions which will exceed 20 percent opacity averaged over a five-minute period. Special provisions are made for soot blowing and ash removal.

Visible emissions from a waste gas flare for more than five minutes during any two-hour period are prohibited except during major upsets.

Regulation II governs sulfur compound emissions. Although emission limits are not specified for natural gas processing plants, general limits for H_2S are established for all sources based on thirty-minutes average ground level concentrations at the property line.

Regulation V has the most direct bearing on the natural gas processing industry. This regulation was adopted for the abatement of photochemical smog in heavily populated areas where this is a problem at the current time. It is to apply only in Aransas, Bexar, Brazoria, Calhoun, Dallas, El Paso, Galveston, Travis, and Victoria Counties. Crude oil and condensate are generally excluded from the group of volatile organic compounds known to be causing small problems. However, in some of the rules, they are not specifically excluded. The following rules under Regulation V should be noted:

Rule 502.1.

Volatile organic compounds other than crude oil and condensate stored in containers with a capacity of more than 25,000 gallons are to be equipped with a means of preventing vapor loss to the atmosphere.

Rule 502.2.

New stationary vessels of more than 1,000 gallons capacity and for storing volatile organic compound other than crude oil and condensate are to be equipped with submerged fill pipes unless it is of a pressure type or fitted with a vapor recovery system.

Rule 502.3.

Crude oil and condensate storage containers are exempt from vapor control regulations of Rules 502.1 and 502.2.

Rule 503.

Except for crude oil, volatile organic compound loading facilities averaging 20,000 gallons a day are to be equipped with vapor collection systems. Ships and barges are exempt.

Rule 505.

Certain hydrocarbons and other compounds may be disposed of only by proper burning in excess of 1300°F smokeless flares or incinerators.

Rule 506.

Compliance with this regulation is required by December 31, 1972. Progress reports required every four months beginning September, 1972.

Finally, Regulation VI is the general permit regulation. Anyone who plans to construct a new facility or modify an existing facility which may emit air contaminants must obtain a construction permit before the work is begun and must also obtain an operating permit within 60 days after startup.

Solid Waste

Texas has a comprehensive solid waste management which meets the requirements provided in RCRA. EPA has granted Texas interim authorization to carry out its program for two years from October 21, 1978 to October 21, 1980.

TABLE 8

OUTLINE SUMMARY OF RULE 8 OF THE TEXAS RAILROAD COMMISSION

A. Fresh surface and groundwater shall be protected from pollution.

B. Exploratory well drilling, completion, or abandonment must be conducted so as to not pollute surface or subsurface waters.

C. Earthen salt water pits prohibited.

  (1) Salt water disposal pits prohibited.

    a. Burning pits allowed (smoke prohibited by TACB rules).
    b. Impervious pits may be approved by the Commission.
    c. Except where permitted by the Commission, brine discharges into water courses prohibited. (This includes bays and estuaries.)
    d. Off lease disposition of salt water must be permitted by Commission.

  (2) Exceptions may be granted with good cause. (TRC will certify applications to the Environmental Protection Agency (EPA) to discharge brine into navigable waters under certain conditions.)

  (3) Violators penalized by pipeline severance.

  (4) Unused pits shall be backfilled.

D. Pollution Prevention

  (1) Operators shall not pollute offshore and adjacent estuarine waters.

  (2) Drilling and production shall be done so as to prevent pollution. In particular, the following procedures shall be used:

    a. No harmful liquid wastes may be discharged. Salt water and other materials from which harmful constituents have been removed are permitted.
    b. No oil or other hydrocarbons to be discharged.
    c. Decks of drilling and workover platforms shall be curbed and wastes contained.
    d. Solid waste may be burned and ashes disposed of in the water. Edible garbage may also be discharged but solids such as cans and bottles must go to shore.
    e. Only oil-free cuttings and fluids from mud systems may be disposed in the water.
    f. Fluids from offshore wells shall be contained with adequate safeguards to prevent pollution.

TABLE 8
(Continued)

OUTLINE SUMMARY OF RULE 8
OF THE TEXAS RAILROAD COMMISSION

g. Producing platforms shall be curbed and equipped to collect wastes in a collecting tank or sump.
h. Any person observing water pollution shall report it to the Commission.
i. Pollution shall be corrected immediately by the responsible operator.

(3) The Commission may suspend operations of a violator.

(4) Provisions of Rule 8D are applicable to operations on inland and fresh waters of Texas.

SECTION 5

NATURAL GAS PROCESSING OPERATIONS

The natural gas extracted from the well has a variety of undesirable impurities and valuable fractions which must be removed or separated prior to sale to an end user. Knockout drums, dehydration, refrigeration, amine and carbonate absorption and solid bed sweetening are used to remove impurities such as water, mercaptans, hydrogen and carbonyl sulfide, carbon dioxide and carbon disulfide. Valuable hydrocarbons such as natural gasoline, NGL, LPG, naphtha, kerosene and isobutane which are worth more as liquid mixtures are stripped from the raw gas in refrigeration units and knockout drums. They are also removed to prevent pipeline freeze ups and other operational difficulties in liquefaction plants. Figure 7 shows a schematic of the general natural gas processing steps used to purify and separate the raw gas into useful products. Typical sales specifications for pipeline quality gas are:

Heating Value: 37.6 MJ/m^3 (1000 BTU/ft^3)

Hydrogen Sulfide: <6 mg/m^3 (0.25 grains/100 ft^3)

Total Sulfur: 120-480 mgm^3 (5-20 grains/100 ft^3)

Water Dewpoint: <190°K (-120°F)

The following sections describe in more detail the operations used to process raw natural gas into marketable products.

LIQUID SEPARATION

The initial gas-liquid separation is typically done in a three stage well head unit, shown in Figure 8. The produced water, crude oil and heavy hydrocarbon liquids are stripped from the gas at this point usually in close proximity to a well head or group of wells. The motive force to operate this separator is supplied by the well pressure head or by pumps. Glycol or methanol injected into the well stream to prevent freezing may also be stripped at this point. The gas, relatively liquid free, is then cooled by heat exchangers to near-freezing to reduce the water and liquid hydrocarbon content even further.

ACID GAS REMOVAL

Acid gas removal, or "sweetening", is necessary for an increasing percentage, presently 6%, of the domestic gas production, and usually follows the liquid separation step. The hydrogen sulfide (H_2S) and carbon dioxide

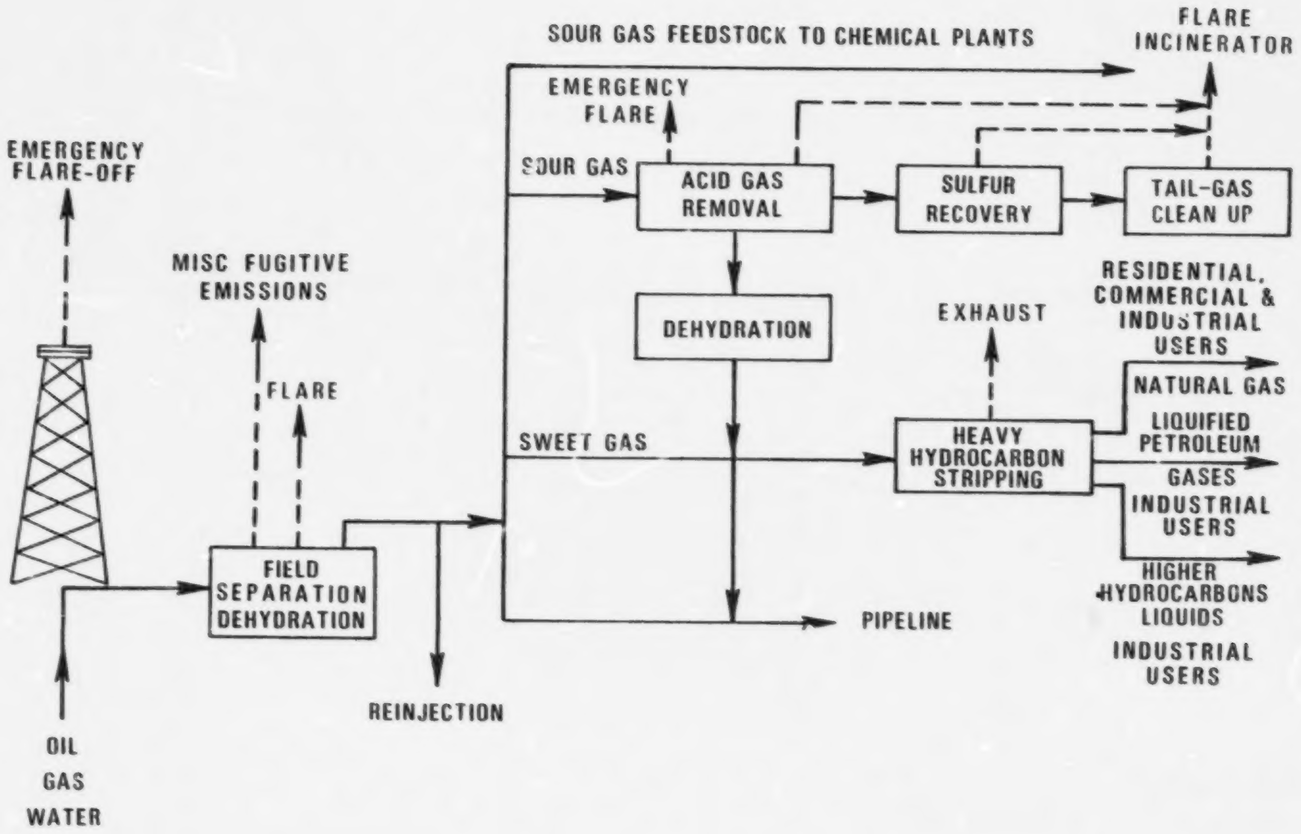

EMERGENCY FLARE-OFF
MISC FUGITIVE EMISSIONS
FLARE
OIL
GAS
WATER
FIELD SEPARATION DEHYDRATION
REINJECTION
SOUR GAS FEEDSTOCK TO CHEMICAL PLANTS
EMERGENCY FLARE
SOUR GAS
ACID GAS REMOVAL
SULFUR RECOVERY
TAIL-GAS CLEAN UP
FLARE INCINERATOR
DEHYDRATION
SWEET GAS
EXHAUST
HEAVY HYDROCARBON STRIPPING
PIPELINE
RESIDENTIAL, COMMERCIAL & INDUSTRIAL USERS
NATURAL GAS
LIQUIFIED PETROLEUM GASES
INDUSTRIAL USERS
HIGHER HYDROCARBONS LIQUIDS
INDUSTRIAL USERS

Figure 7: Flow diagram of the natural gas industry.(9)

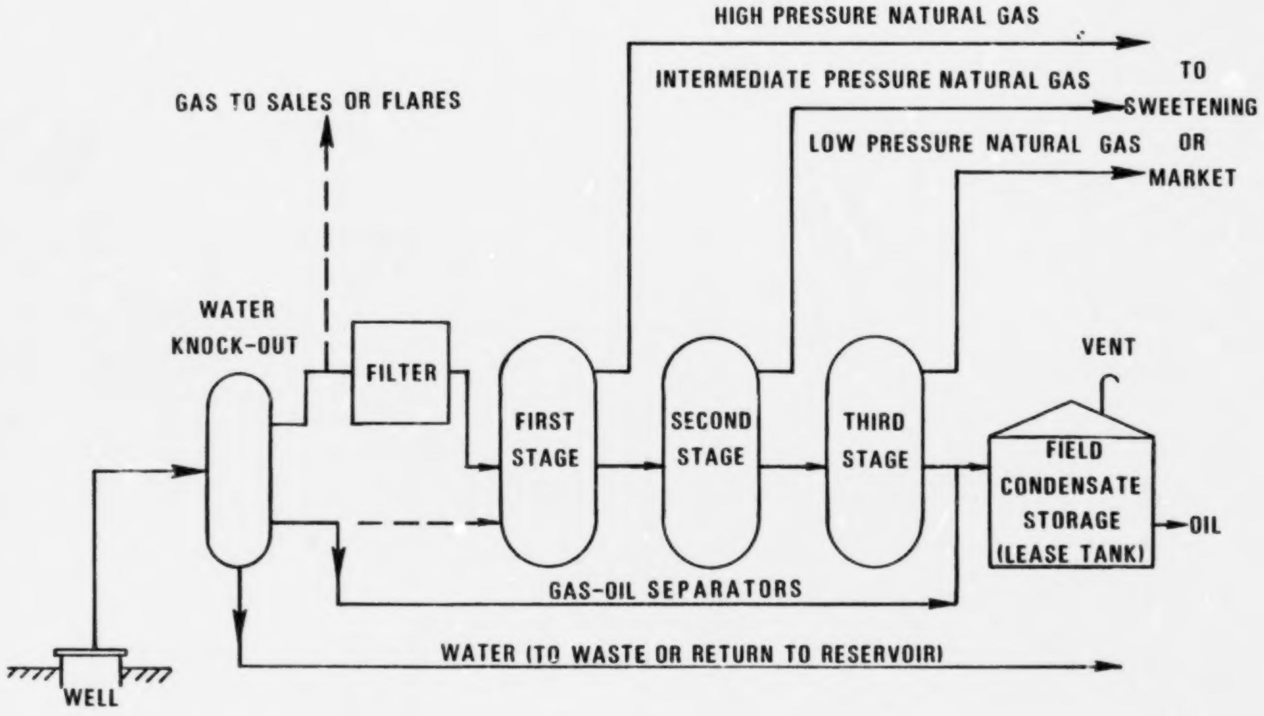

HIGH PRESSURE NATURAL GAS
INTERMEDIATE PRESSURE NATURAL GAS
LOW PRESSURE NATURAL GAS
TO SWEETENING OR MARKET
GAS TO SALES OR FLARES
WATER KNOCK-OUT
FILTER
FIRST STAGE
SECOND STAGE
THIRD STAGE
VENT
FIELD CONDENSATE STORAGE (LEASE TANK)
OIL
GAS-OIL SEPARATORS
WATER (TO WASTE OR RETURN TO RESERVOIR)
WELL

Figure 8: Flow diagram for a three-stage wellhead separation unit.(10)

(CO_2) have limited solubility in liquefied natural gas and would cause operational difficulties in liquefaction plants.

Thirty different processes are available for sweetening, which can be divided into five basic categories:

1. Amine Processes
2. Carbonate Processes
3. Physical Absorption
4. Solid Bed Sweetening
5. Stretford Process

Amine Processes

Amine processes are used for approximately 95% of all domestic gas sweetening. A flow diagram of a typical amine process for gas sweetening is presented in Figure 9.

The sour gas enters an absorber, which is a trayed vessel with 20 or more trays in it, where it is contracted with an amine solution and the H_2S and CO_2 are absorbed from the natural gas. The gases leaving the absorber are considered sweet. The knockout drum removes the entrained solution and the gases go on to the next step. The rich solution (liquids) are let down in pressure in a vent tank where the majority of the hydrocarbon gases are released and then used as fuel. The rich solution then enters an exchanger where it is heated and then passed on to a still. In the still or stripper, the solution is stripped of the absorbed H_2S and CO_2 by means of heat applied through a reboiler at the bottom of the tower and by fractionation. The gases are sent overhead to a condenser in which the entrained water and the regenerated solutions are condensed and returned through the heat exchanger to a surge tank and then pumped back to the absorber. A carbon absorption facility is also included to keep the solution clean of impurities such as iron sulfide, non-regenerable compounds, etc. Another impurity that can cause problems, particularly in the sulfur plant, is liquid hydrocarbons. These condense in the still overhead accumulator and surge tank and are then removed via skimming facilities.

There are nine variations to this basic process with the difference primarily being the amine solution used. These nine processes are discussed in more detail in Appendix D.

The four less commonly used sweetening processes are also discussed in Appendix D.

DEHYDRATION

After the removal of the acidic impurities, the gases often remain saturated with water. The water and/or water vapor are removed from the natural gas for several reasons: To prevent formation of hydrates in transmission lines which can plug valves, fittings, and lines when the gas is compressed or cooled; to meet a water dew point requirement for a gas sales contract; and to prevent hardware corrosion from acidic gas streams. The water

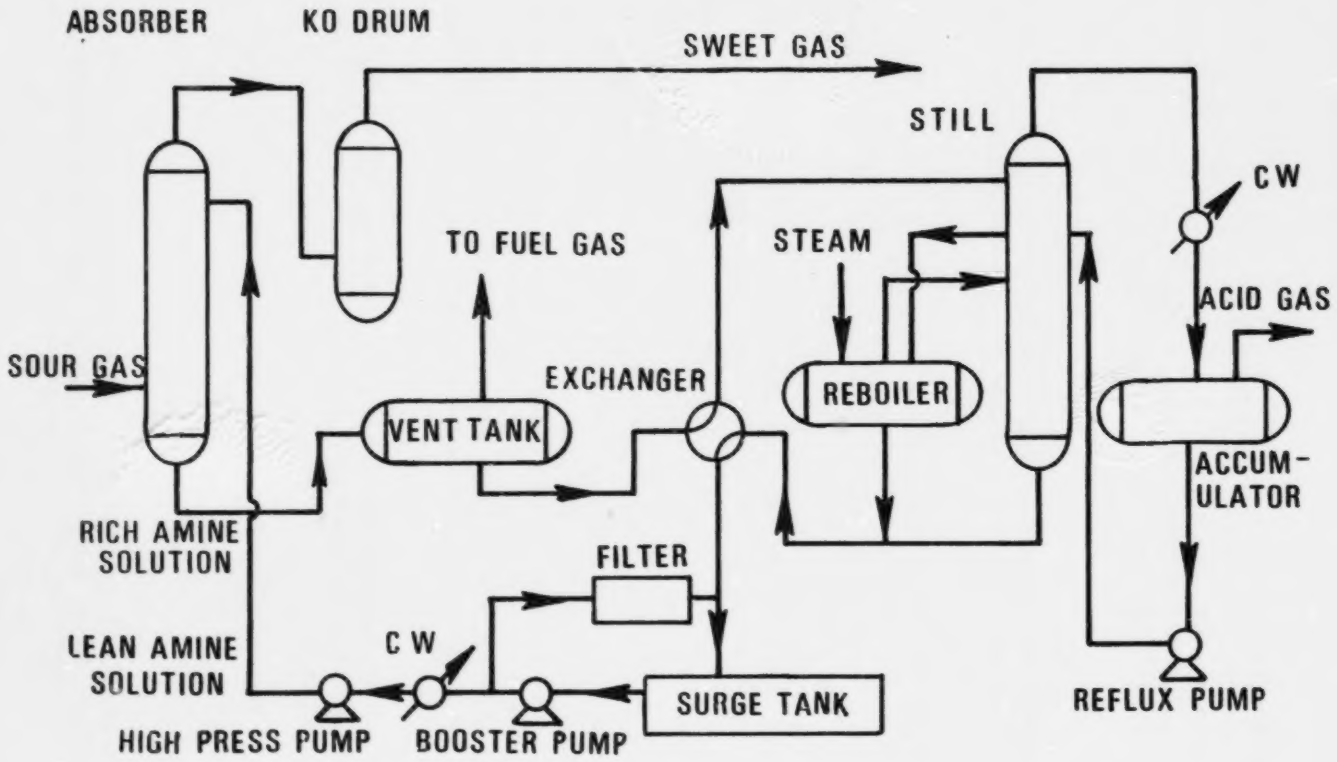

ABSORBER
KO DRUM
SWEET GAS
STILL
CW
TO FUEL GAS
STEAM
ACID GAS
SOUR GAS
EXCHANGER
REBOILER
VENT TANK
ACCUM-
ULATOR
RICH AMINE
SOLUTION
FILTER
LEAN AMINE
SOLUTION
C W
SURGE TANK
REFLUX PUMP
HIGH PRESS PUMP
BOOSTER PUMP

Figure 9: Flow diagram of the amine sweetening process.(11)

concentration in the incoming gas stream should be reduced to 0.76 mg/m^3 (1 ppm) for LNG plants, and approximately 110 mg/m^3 (150 ppm) for interstate shipment.

Techniques for dehydrating natural gas include:

- Absorption using liquid desiccants
- Adsorption using solid desiccants
- Inhibition by injection of hydrate point depressants
- Dehydration by expansion refrigeration

These methods will be discussed in the following subsections.

Liquid Desiccant Absorption

The more common liquids in use for dehydrating natural gas are triethylene glycol (TEG), diethylene glycol (DEG), ethylene glycol (EG), and calcium chloride brine. In general, glycols are used for applications where dew point depressions of the order of 290-320°K (60-120°F) are required. TEG is the most common, principally because of higher glycol vapor losses when DEG and EG are used. Also, greater dew point depressions are obtained with TEG.

The glycol dehydration process, which is typical of the processes using absorbents, is shown in Figure 10. Gas is brought into the system through an inlet scrubber to remove any entrained liquid water or hydrocarbon. The gas is then dried by countercurrent contact with the absorbent in the absorber. Dehydrated gas leaves the system from the top of the absorber and the absorbent containing water leaves from the bottom. Since the absorber is normally operated at pressures 2.0 MPa (290 pounds per square inch, absolute), some gas will be dissolved in the absorbent. This gas is separated in a flash vessel at reduced pressure and delivered to the fuel gas system. The absorption liquid is then fed to a distillation column, or still, for regeneration. Water is distilled overhead, along with a minor amount of gas which is sent to the flare. The regenerated absorbent is recycled to the absorber after cooling by exchange with the feed stream and cooling water.

Solid Desiccant Adsorption

There are a number of commercially-available desiccants that are used for gas dehydration. The most widely used are alumina, silica gel, and silica-alumina beads, and molecular sieves. These desiccants can be regenerated so that they can be used through many cycles of absorption and reactivation. Some of them can produce exit water content as low as 0.76 mg/m^3 (1 ppm) or less.

The basic process, shown in Figure 11, consists of two dehydration vessels to permit continuous operation since the adsorbent is regenerated in place. Gas is brought into the system through an inlet scrubber to remove any entrained liquid water. The main flow, to the No. 1 desiccant tower, flows downward through the tower and dehydration gas leaves the process from the bottom. The No. 2 tower is regenerated while the first is on-stream. A bypass stream from the main gas flow is heated and passed through the second tower.

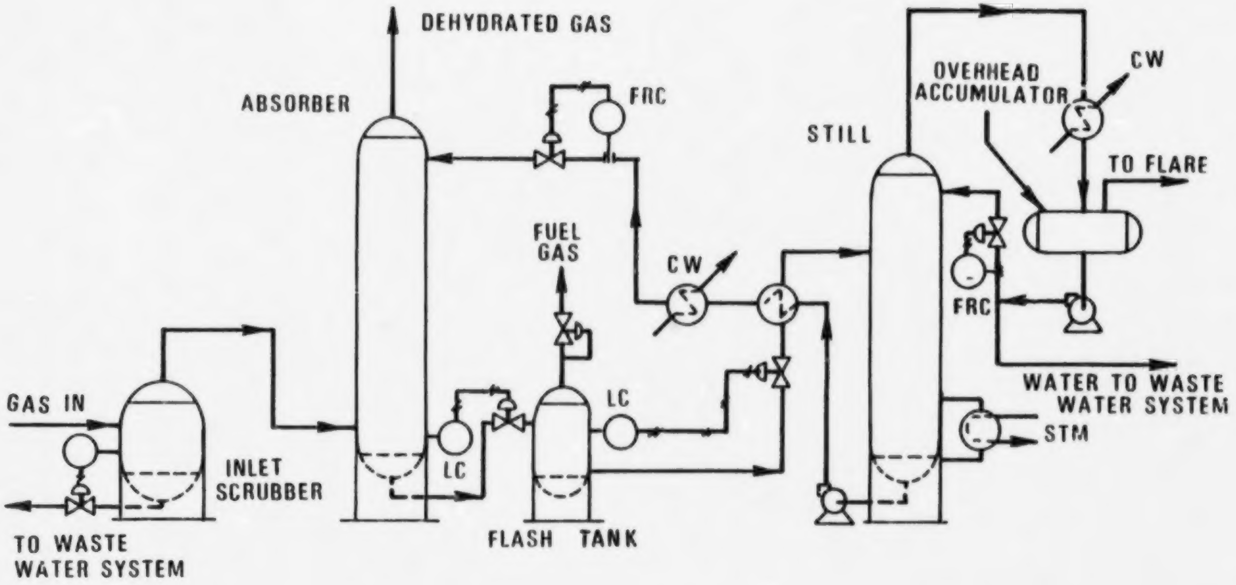

DEHYDRATED GAS
ABSORBER
FRC
OVERHEAD
ACCUMULATOR
CW
STILL
TO FLARE
FUEL
GAS
CW
FRC
GAS IN
LC
WATER TO WASTE
WATER SYSTEM
STM
INLET
SCRUBBER
LC
TO WASTE
WATER SYSTEM
FLASH TANK

Figure 10: Flow diagram of the glycol dehydration process.(12)

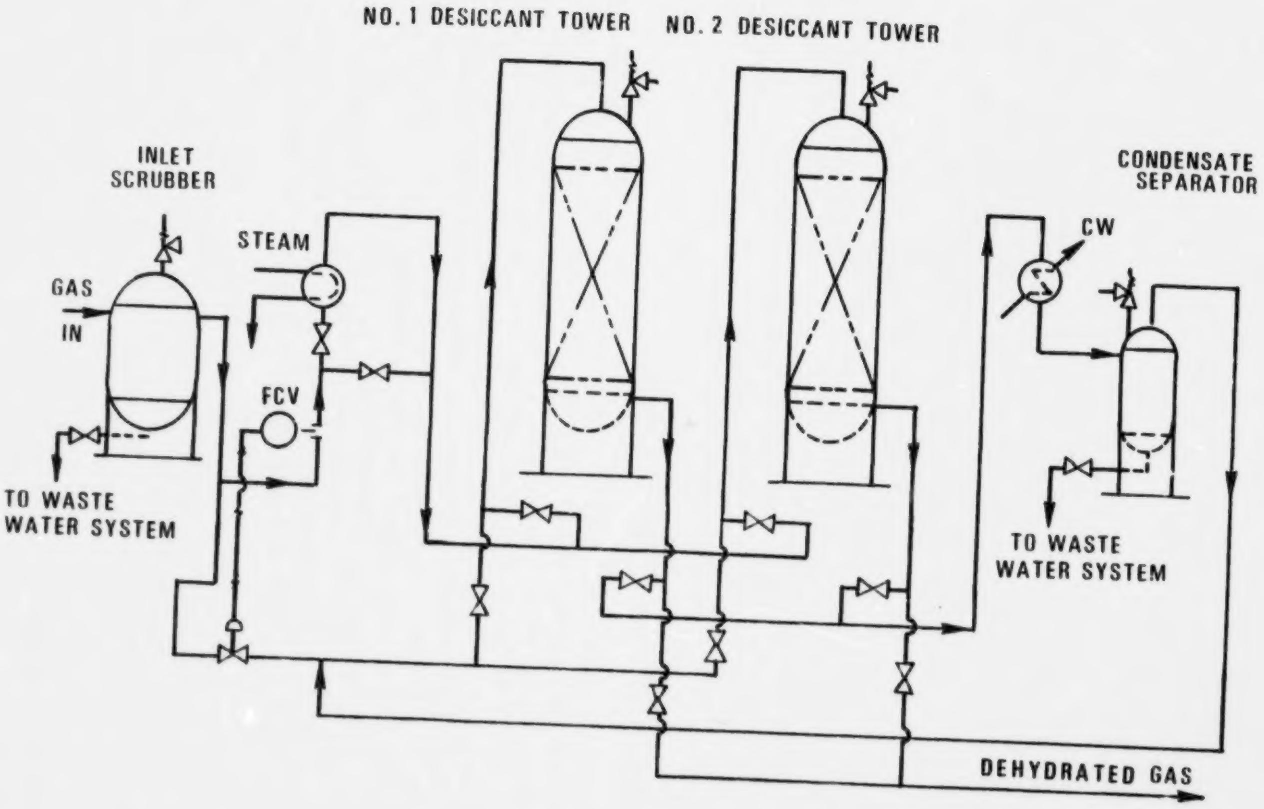

NO. 1 DESICCANT TOWER
NO. 2 DESICCANT TOWER
INLET SCRUBBER
STEAM
GAS IN
FCV
TO WASTE WATER SYSTEM
CONDENSATE SEPARATOR
CW
TO WASTE WATER SYSTEM
DEHYDRATED GAS

Figure 11: Flow diagram of the adsorbent dehydration process.(13)

Gas and water vapor from the tower are cooled to condense the water. The water is separated from the gas in the condensate separator and the gas is returned to the main gas stream. After regeneration, the desiccant bed is cooled by bypassing the heater and passing cool gas through the tower.

The use of alumina as the desiccant will produce a dew point under 200°K (-100°F). A disadvantage is that alumina tends to require more regeneration heat than some other desiccants. It also tends to absorb heavy hydrocarbons which are difficult to remove in regeneration. Alumina is alkaline and is subject to reaction with mineral acids which are sometimes found in well-treating chemicals.

Silica gel and silica-alumina beads will produce dry gas with water content as low as 7.6 mg/m^3 (10 ppm). Their regeneration is the easiest of the various desiccants discussed. They also absorb heavy hydrocarbons but release them more easily than alumina in regeneration. They are acidic materials and will react with caustic, ammonia, and other basic materials. Liquid water causes them to crack or break.

Molecular sieves are discussed in Appendix D as a method for acid gas sweetening. They are also used for dehydration and can produce dry gas water contents as low as 0.76 mg/m^3 (1 ppm). An advantage is that they tend not to adsorb heavy hydrocarbons due to molecular size discrimination. A disadvantage is that the external surface of the particles is subject to fouling by oil or glycol carryover. Also, they require the highest reactivation temperatures and are subject to irreversible acid attack because they are alkaline.

Injection of Hydrate Point Depressants

Hydrate point depressants are used along with expansion refrigeration (discussed in the following section) if there is danger of forming hydrates in the pre-cooling heat exchanger. The most common inhibitor used is liquid glycol injected into the gas stream. Glycols have low volatility and are easily separated from liquid hydrocarbons and from the water they absorb. They allow continuous hydrate control in plants that have suitable regeneration and recycle equipment. Ethylene, diethylene, and triethylene glycols have all been used for glycol injection with ethylene glycol being the most common due to cost and operating characteristics. Glycol must be present at the very point where wet gas is cooled to its hydrate temperature. The glycol and its absorbed water are separated from the gas stream along with the liquid hydrocarbons. A flow diagram of this process is presented in Figure 12.

Another inhibitor used is methanol. It is frequently used for intermittent or continuous injection in natural gas field-gathering systems and transmission lines to protect against hydrate formation when the gas is cooled by the environment. In gas-processing plant operations, intermittent injection is frequently used where there is a slow build-up of hydrates.

Expansion Refrigeration

With wellheads under positive pressure, dehydration can be accomplished by expansion refrigeration. The gas stream is cooled by adiabatic expansion,

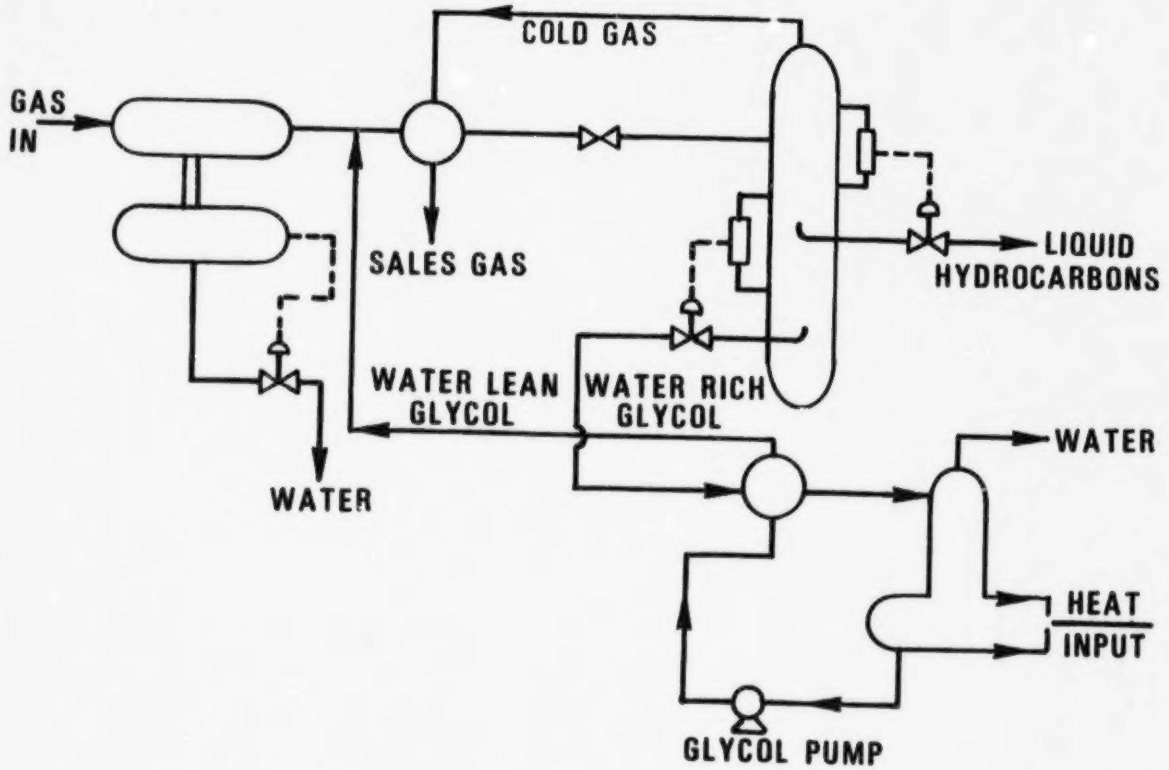

GAS IN
COLD GAS
SALES GAS
LIQUID HYDROCARBONS
WATER LEAN GLYCOL
WATER RICH GLYCOL
WATER
WATER
HEAT INPUT
GLYCOL PUMP

Figure 12: Flow diagram of the glycol injection dehydration process.(14)

with the incoming gas being heat exchanged with cold off-gas from the separator. Expansion refrigeration without an inhibitor is used only when the available pressure drop allows the desired water dew point to be attained without the formation of hydrates while pre-cooling the inlet gas stream ahead of the point of pressue drop. Hydrates are allowed to form and are immediately collected in the low temperature separator. The warm incoming gas stream is directed through a heating coil to melt the hydrates.

SULFUR RECOVERY

The next step in natural gas processing is the conversion of H_2S to high purity sulfur. This is accomplished in a Claus sulfur-recovery unit. The H_2S containing acid gas stream, which results from the sweetening processes, is subjected to either a "once-through" or "split-stream" process.

The once-through scheme is selected if the acid gas feed contains 30-40 mol % H_2S or greater since it gives the highest overall sulfur recovery and permits maximum heat recovery at a high temperature. In this scheme, all of the acid gas is fed to a reaction furnace, along with enough air to burn one-third of the H_2S to SO_2 and all hydrocarbons completely. Sufficient retention time is then provided to allow reaction of the SO_2 generated with the unburned H_2S to form sulfur vapor. The thermal conversion step takes place above 1300°K (1,900°F) with no catalyst present. Up to 70% of the overall conversion of H_2S to sulfur can take place at this point. The hot gases then pass through a waste-heat boiler, where they are typically cooled to about 560°K (550°F). If a two-pass boiler is used, the gases are cooled to 800-910°K in the first pass, and on to 560°K (550°F) in the second pass. The hot gas from the first pass serves as the source for hot-gas bypass streams, as a method of reheating which minimizes energy costs.

If the H_2S concentration in the feed is low, a split-flow scheme is used. In this scheme a portion of the feed is burned completely to SO_2 and combined with the remainder of the feed to provide the proper H_2S/SO_2 ratio for the remainder of the process. The optimum H_2S/SO_2 ratio in the tail gas is 2:1, which will give the maximum sulfur conversion. A ratio either above or below 2:1 will cause a loss in conversion efficiency.

Following the waste-heat boiler, a sulfur condenser is provided to condense and remove the sulfur produced by the thermal-conversion step in the reaction furnace. After the condensation step, the gas must be reheated before it flows to the first catalytic converter. The first condenser usually produces 0.3MPa (45 psia) steam and operates with a gas-outlet temperature 440-460°K (340-370°F). The gas is reheated 500-530°K (450-500°F) before entry into the first converter.

If the feed gas contains appreciable CO_2 (say more than 8-10 mol %), the first converter is operated somewhat hotter than the subsequent converters to enhance COS and CS_2 conversion to sulfur in the first converter. Frequently a special catalyst is placed in the converter to hydrolyze the COS and CS_2 to H_2S and CO_2 to prevent their emissions from the plant.

After the first condenser, the Claus plant consists of a series of "reheat, conversion, and condensation" steps. These steps are repeated as many times as desired, but two or three catalytic converters are usually the optimum choice. Typically all the condensers produce low-pressure steam in the range of 0.38-0.52 MPa (40-60 psig) with the last condenser producing 0.24 MPa (20 psig) steam. The gas outlet from the last condenser usually operates at 400-405°K (260-265°F) which is safely above the sulfur-solidification point of 390°K (246°F).

The inlet gas to each catalytic converter is usually reheated to 470-490°K (400-430°F), with the first converter inlet running 500-530°K (450-500°F). There are four basic reheat schemes which may be used: (1) hot-gas bypass, (2) in-line burners, (3) gas-to-gas exchangers, and (4) indirect heaters, using either fuel firing or steam heating. These are listed, in the order of increasing cost and effectiveness in increasing the overall sulfur conversion.

The catalyst commonly used in Claus plants is 2/4 mesh bauxite. New, improved catalysts are available (such as Kaiser S-201 and Thone-Progil CR), which can have advantages over bauxite such as greater resistance to sulfate formation, lower pressure drop, better COS and CS_2 conversion, etc.

The sulfur recovery efficiency of a Claus plant can range from 70-98% depending on the H_2S concentration in the feed gas, the number of catalytic stages, and the quality of catalyst used. The unrecovered sulfur is converted to SO_2 in the tail-gas incinerator, or further processed via one of the many tail-gas conditioning processes.

A flow diagram of the Claus process is presented in Figure 13.

TAIL-GAS CONDITIONING

Several processes are available for cleanup of the remaining sulfur compound in the tail gas from a Claus plant. Some of these procedures are very efficient and carry the Claus reaction to further completion with 99+% of the sulfur in the acid gas stream removed overall.

The six leading tail-gas treatment processes are: (1) Parson's Beavon Process; (2) Pritchard's Clean Air Process; (3) IFP-2 Process; (4) Shell's SCOT Process; (5) SNPA/Lurgi's Sulfreen Process; and (6) the Wellman Lord Process. The Sulfreen and IFP Processes will not yield 1.4 g/m^3 (500 ppm) SO_2 emissions. Another process that is viable but which does not yield a 1.4 g/m^3 (500 ppm) SO_2-emissions level is the SNPA Catalytic Oxidation Process. Chiyoda's process is viable, but it produces a gypsum by-product which creates a solid-disposal problem and is not used in the United States. Additionally, there are eight other processes that are in an early stage of development or commercialization. These eight are: (1) Stauffer's Aquaclaus Process; (2) Shell's SFGD Process; (3) Westvaco's Adsorption Process; (4) USBM's Citrate Process; (5) Townsend Process; (6) ASR's Sulfoxide Process; (7) Trentham's Trendor-M Process; and (8) Amoco's CBA Process.

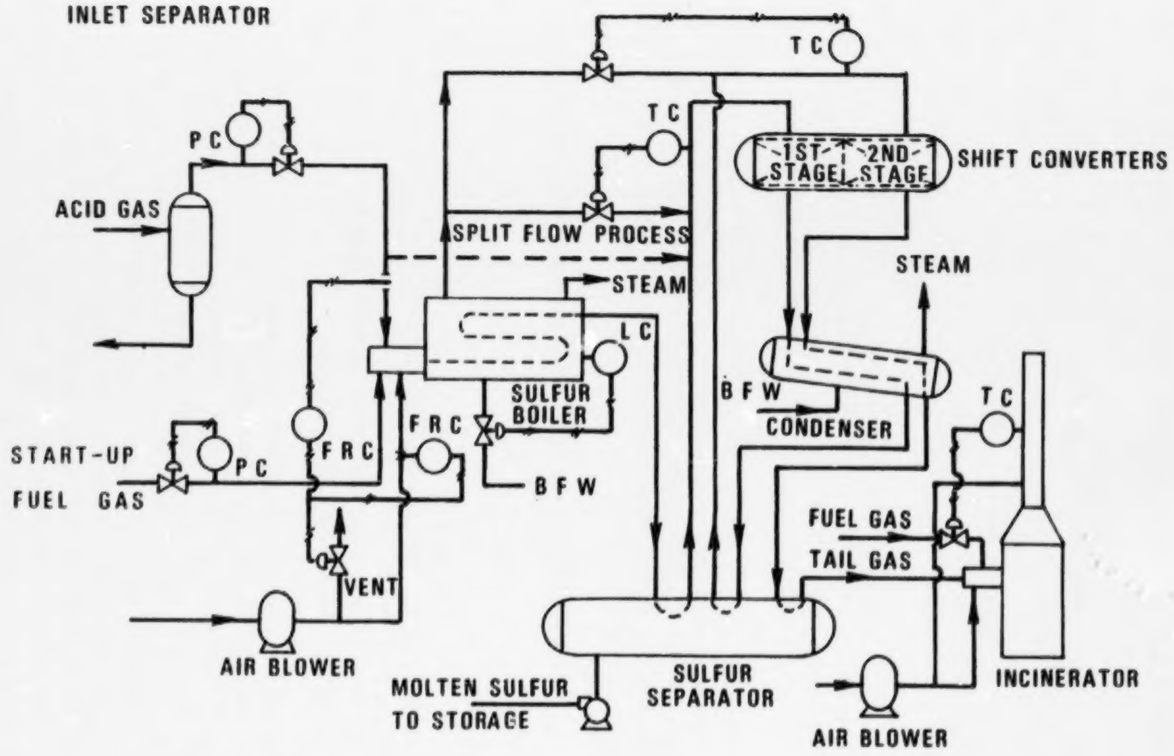

INLET SEPARATOR
ACID GAS
P C
START-UP
FUEL GAS
P C
F R C
F R C
VENT
AIR BLOWER
SPLIT FLOW PROCESS
STEAM
L C
SULFUR BOILER
B F W
T C
T C
1ST STAGE
2ND STAGE
SHIFT CONVERTERS
STEAM
B F W
CONDENSER
MOLTEN SULFUR TO STORAGE
SULFUR SEPARATOR
FUEL GAS
TAIL GAS
T C
AIR BLOWER
INCINERATOR

Figure 13: Flow diagram of a Claus sulfur plant.(12)

These 16 processes can be divided into two main categories: Wet-scrubbing processes and dry-bed processes. These two main categories can be further subdivided into five subcategories: (a) Wet-reduction to H_2S with subsequent absorption or reaction; (b) wet-oxidation to SO_2 with subsequent absorption or reaction; (c) wet-expansion of the Claus reaction in liquid phase with catalyst present; (d) dry-expansion of the Claus reaction on a solid bed; and (e) dry-oxidation to SO_2 with subsequent absorption or reaction. These categories and their associated processes are discussed further in the following paragraphs.

Wet-Reduction Processes

Shell SCOT Process --

The Shell Claus Off-Gas Treating (SCOT) process can increase the sulfur recovery efficiency of Claus units from the usual level of about 95% to more than 99.8%. The process essentially consists of a reduction section and an alkanolamine absorption section.

In the reduction process, all sulfur compounds and free sulfur present in non-incinerated Claus off-gas are completely converted into H_2S over a cobalt/molybdenum catalyst at 570°F (570°K) in the presence of H_2 or a mixture of H_2 and CO. Reducing gas can be supplied from an outside source, or a suitable reducing gas can be generated by substoichiometric combustion in the direct heater. This heater is required in any case for heating process gas to the reactor inlet temperature. Reactor effluent is cooled subsequently in a heat exchanger and a cooling tower. Water vapor in the process gas is condensed, and condensate is sent to a sour water stripper.

Cooled gas, normally containing up to 3% vol H_2S and up to 20% vol CO_2, is countercurrently washed with an alkanolamine solution in an absorption column specially designed to absorb almost all H_2S but relatively little CO_2. The treated gas from the absorption column, which contains only a trace of H_2S, is burned in a standard Claus incinerator.

The concentrated H_2S is recovered from the rich absorbent solution in a conventional stripper and is recycled to the Claus unit.

The benefits of this process are: Easy adaptability to an existing Claus plant, the use of familiar process technology and equipment, easy and flexible operation, elimination of secondary air and water pollution, and a high degree of sulfur removal over a wide range of operating conditions. It is also favored since initial costs of installation are relatively low.

A flow diagram is presented in Figure 14.

Parson's Beavon Process --

This process consists of three basic steps: (1) Hydrogenation of sulfurous compounds to H_2S in a catalytic converter; (2) cooling of the converter-effluent gases; and (3) conversion of the H_2S in the tail gas from the cooler to elemental sulfur by the use of either the Stretford or Takahax processes. This proven process is preferred if the tail gas has a "high" CO_2 content (20-40% by volume).

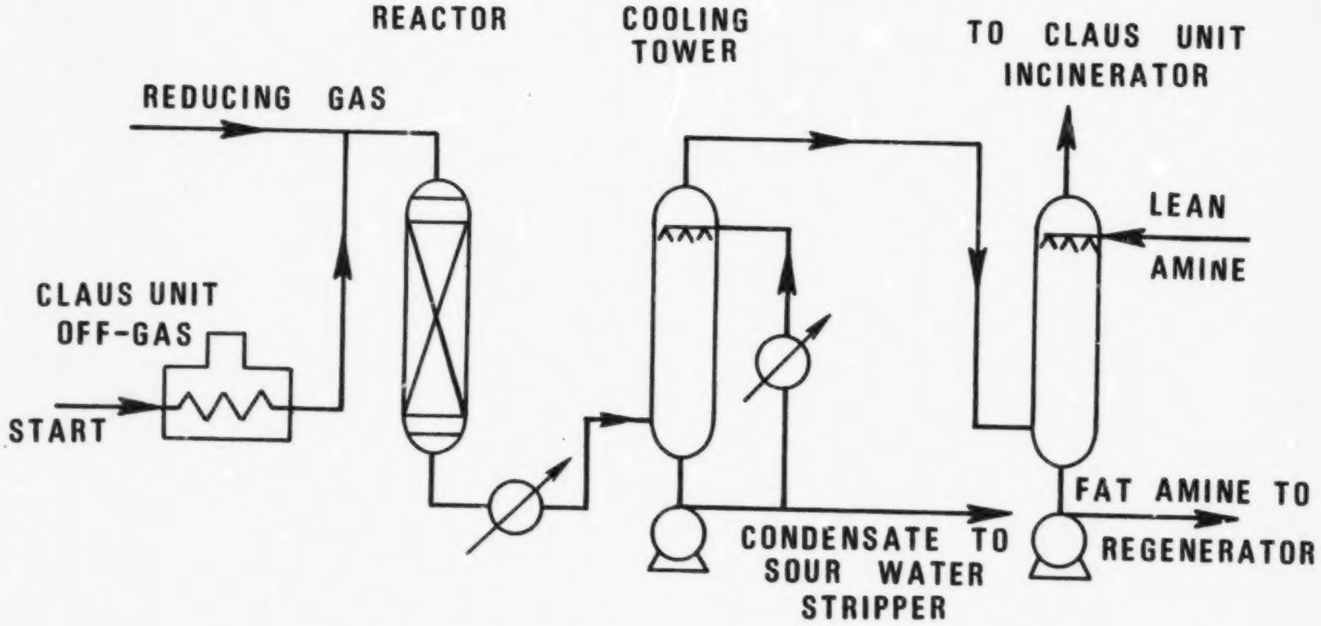

REACTOR
COOLING TOWER
TO CLAUS UNIT INCINERATOR
REDUCING GAS
LEAN AMINE
CLAUS UNIT OFF-GAS
START
FAT AMINE TO REGENERATOR
CONDENSATE TO SOUR WATER STRIPPER

Figure 14: Flow diagram of the SCOT process.(13)

In the first portion of the process, all sulfur compounds in the Claus tail gas (SO_2, SO_x, COS, CS_2) are converted to H_2S. The tail gas is heated to reaction temperature by mixing with the hot combustion products of fuel gas and air. This combustion may be carried out with a deficiency of air if the tail gas does not contain sufficient H_2 and CO to reduce all of the SO_2 and SO_x to H_2S. The heated gas mixture is then passed through a catalyst bed in which all sulfur compounds are converted to H_2S by hydrogenation and hydrolysis. The hydrogenated gas stream is cooled by direct contact with a slightly alkaline buffer solution before entering the H_2S removal portion of the process.

The Stretford or Takahax process is then used to remove H_2S from the hydrogenated tail gas. The Stretford process involves absorption of the H_2S in an oxidizing alkaline solution. The oxidizing agents in the solution convert the H_2S to elemental sulfur, then are regenerated by air oxidation, which floats the sulfur off as a slurry. This sulfur slurry is then filtered, washed, and melted to recover the Stretford solution and produce a high-purity sulfur product.

A flow diagram is presented in Figure 15.

The Japanese Takahax process is essentially the same as the Stretford process, except for the chemicals used. Takahax uses an absorbent solution of sodium carbonate: 1, 4-naphthoquinone, and 2-sulfonate sodium.

Pritchard's Clean Air Process --

This process recovers 99.9% of the sulfur from the Claus plant tail gas, leaving no more than 570 mg/m^3 (200 ppm) SO_2 equivalent in the effluent. This process is installed upstream of the incinerator in a conventional Claus plant and consists of three stages, installed stepwise, to achieve decreasing amounts of sulfur emitted to the atmosphere. The first stage removes SO_2 and sulfur by aqueous scrubbing in a tower which quenches the gas from 400 to 300°K (270 to 120°F). The second stage removes the H_2S in a Stretford unit. Stage three reduces the COS and CS_2 by approximately 90% by operating in Claus reactors at elevated temperatures.

Trentham's Trencor-M Process --

This process is similar to the SCOT process. The tail gas is heated to 560°K(550°F) and reacted with hydrogen over a noble-metal catalyst to reduce all sulfurous compounds to H_2S. The stream is then cooled and pumped to an amine absorber.

Wet-Oxidation Processes

Wellman-Lord Process --

Tail-gas from sulfur units is first incinerated to convert all of the sulfur compounds originally present (H_2S, COS, CS_2, etc.) to SO_2. The hot gases are cooled in a waste heat boiler, then quenched and fed to the SO_2 absorber. (See Figure 16.)

The acid bottoms from the absorber flow to the oxidizer, where air is blown into the tower. The oxidizing catalyst is an inexpensive, nonpoisonous compound that is soluble in the acid. Part of the acid goes from the oxidizer

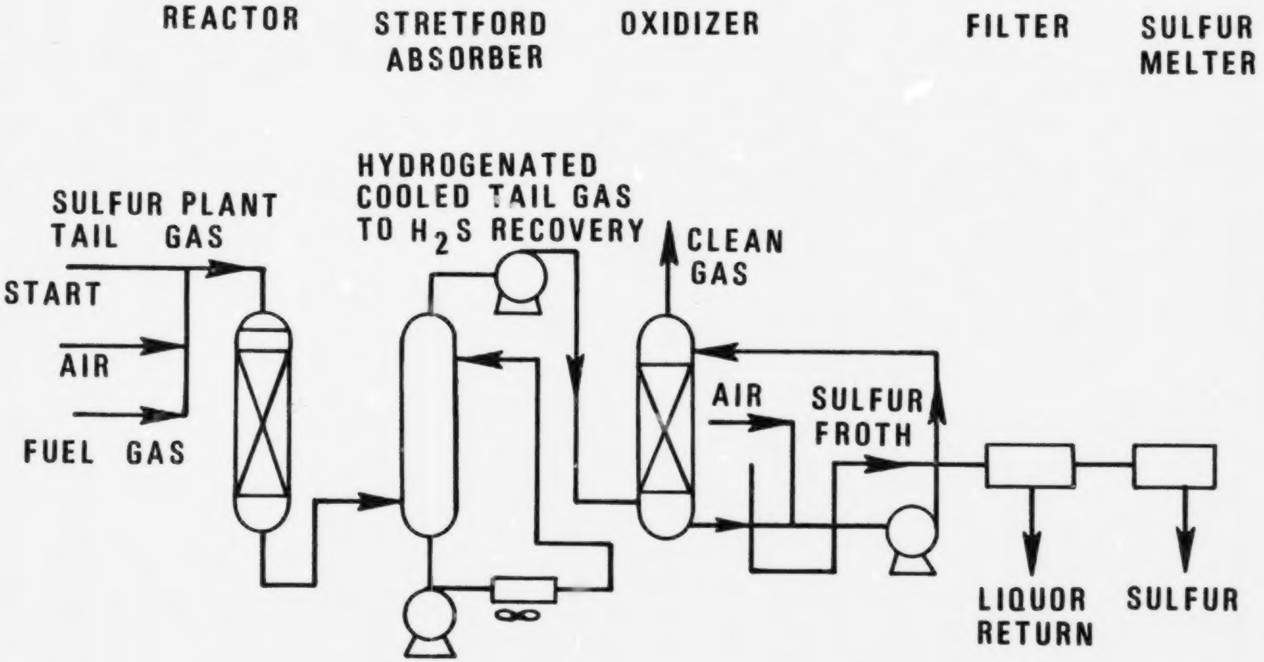

REACTOR
STRETFORD ABSORBER
OXIDIZER
FILTER
SULFUR MELTER
SULFUR PLANT TAIL GAS
START
AIR
FUEL GAS
HYDROGENATED COOLED TAIL GAS TO H_2S RECOVERY
CLEAN GAS
AIR
SULFUR FROTH
LIQUOR RETURN
SULFUR

Figure 15: Flow diagram of the Beavon process.(13)

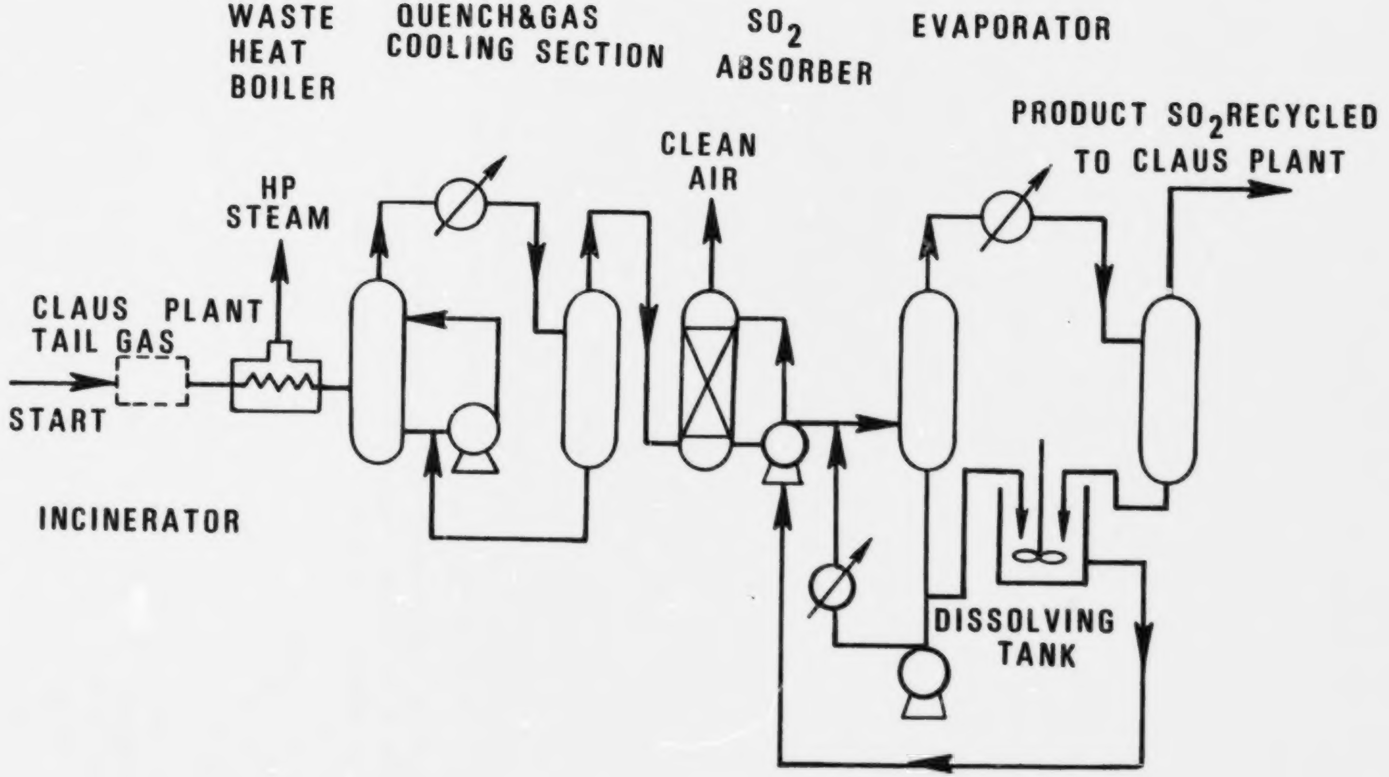

WASTE HEAT BOILER
QUENCH&GAS COOLING SECTION
SO_2 ABSORBER
EVAPORATOR
PRODUCT SO_2 RECYCLED TO CLAUS PLANT
CLEAN AIR
HP STEAM
CLAUS PLANT TAIL GAS
START
INCINERATOR
DISSOLVING TANK

Figure 16: Flow diagram of the Wellman-Lord process.(13)

back to the absorber, while the rest goes to a crystallizer. Limestone is mixed with the acid solution in the crystallizer to form gypsum crystals. Despite high initial costs this tail gas clean up process is preferred if the tail gas has a high CO_2 content.

USBM Citrate Process --

In the U. S. Bureau of Mines (USBM) Citrate process, the Claus tail gas is first incinerated and cooled by conventional means. Then the gas flows to an absorption tower, where the SO_2 is absorbed in an aqueous solution of citric acid and other carboxylates. The rich solution flows to a stirred reactor vessel where H_2S is added to precipitate elemental sulfur.

The sulfur is concentrated by air flotation, and is ultimately melted and drawn off from the system as a liquid. The H_2S required for the reaction step is taken from the feed stream to the Claus plant.

Wet-Extension Processes

IFP Process --

There are two different schemes in the Institute Francais de Petrole (IFP) process. IFP-1 removes H_2S and SO_2 from tail-gas to an SO_2 level of 4.3 to 5.7 g/m^3 (1500 to 2000 ppm). IFP-2 removes the SO_2 to a 1.4 g/m^3 (500 ppm) level or below.

In the IFP-1 process, tail-gas is injected into a packed tower and contacted countercurrent with solvent containing catalyst. Sulfur is formed, collected and removed from the bottom of the tower. Operating temperatures in the tower range from 390-410°K (250-280° F).

In the IFP-2 process (shown in Figure 17), the tail-gas is scrubbed with aqueous ammonia after incinceration. Clean overhead is incinerated and vented up the stack. Brine containing sulfites, bi-sulfites and a small amount of sulfates from the scrubber are evaporated; sulfates are reduced, and mixed SO_2/NH_3 overheads are injected into the bottom of the contactor along with the SO_2 stream. Solvent containing catalyst is circulated countercurrent to the gas flow. Operating temperature in the contactor ranges from 390 to 410°K (250-280° F). Sulfur is formed, collected and removed from the bottom of the tower. Ammonia is removed overhead and returned to the scrubber.

Stauffer Aquaclaus Process --

The Aquaclaus process is a new concept developed by the Stauffer Chemical Co. It is a wet-absorption system that is reported to be capable of producing a treated gas which contains less than 0.27 g/m^3 (100 ppm) of SO_2.

In this process, the Claus tail-gas is first incinerated to convert all sulfur-bearing compounds, such as H_2S, COS, CS_2, etc., to SO_2. Then the stream is cooled in a waste-heat boiler and/or a direct-contact cooler, and is fed to an absorption tower. The SO_2 is absorbed by the Aquaclaus solution, aqueous sodium phosphate.

The rich solvent from the absorber is contacted with fresh H_2S feed, from the front of the Claus plant, in a reactor vessel to form elemental sulfur by

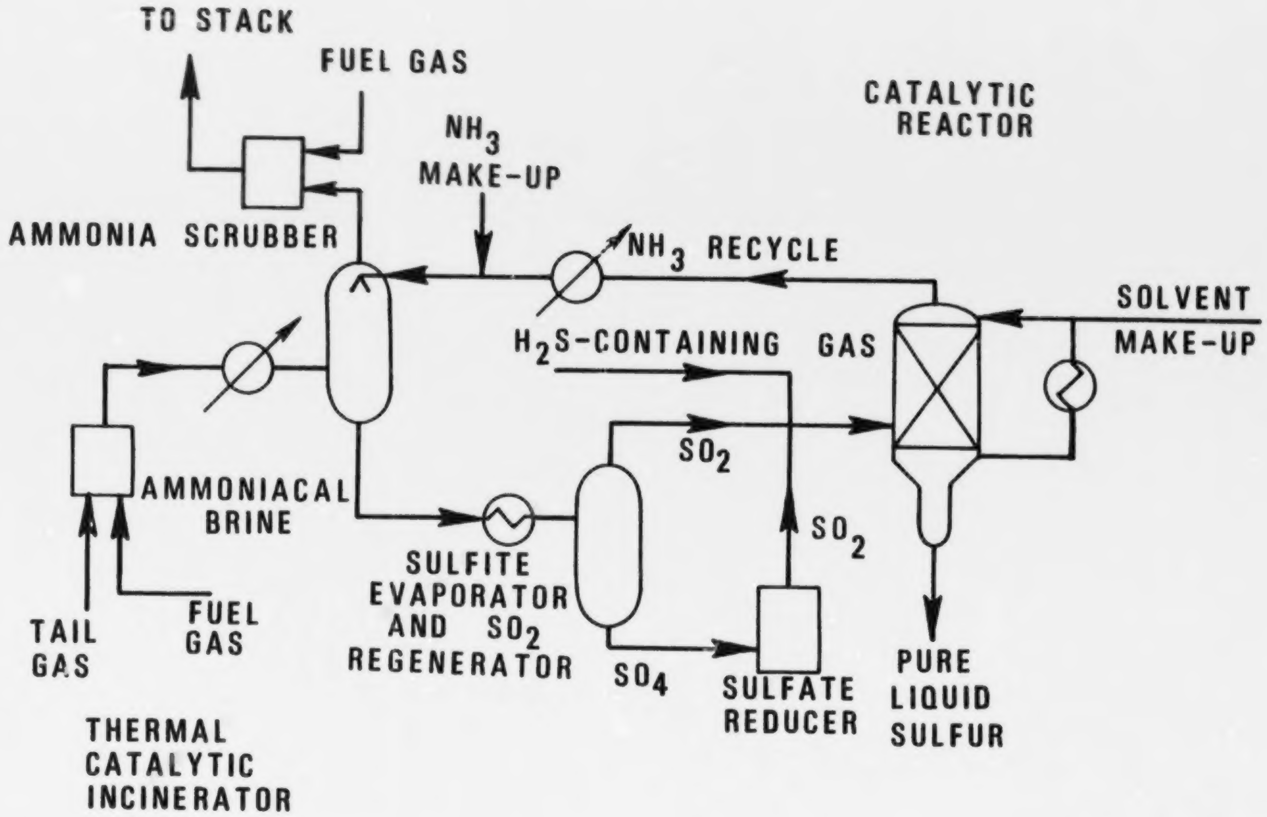

TO STACK
FUEL GAS
NH_3 MAKE-UP
CATALYTIC REACTOR
AMMONIA SCRUBBER
NH_3 RECYCLE
SOLVENT MAKE-UP
H_2S-CONTAINING GAS
SO_2
AMMONIACAL BRINE
SO_2
SULFITE EVAPORATOR AND SO_2 REGENERATOR
TAIL GAS
FUEL GAS
SO_4
SULFATE REDUCER
PURE LIQUID SULFUR
THERMAL CATALYTIC INCINERATOR

Figure 17: Flow diagram of the IFP-2 process.(13)

the classic Claus reaction occurring in an aqueous phase. The solution is heated and liquid sulfur is withdrawn. The Aquaclaus solution is cooled and recirculated to the absorber after the sulfur is separated.

A few disadvantages, such as undesirable side reactions occurring in the absorber and reactor and high maintenance costs, have been noted to date.

Townsend Process --

The Townsend process is similar to the IFP process, in that it uses an organic solvent (such as triethylene glycol) to allow H_2S and SO_2 to react (Claus reaction) to form elemental sulfur. The reactor is operated at a temperature above the melting point of sulfur, so that liquid sulfur is produced from the bottom.

This process may be applied directly to treatment of Claus-plant tail gas, without any preconditioning of the gas. As far as is presently known, COS or CS_2 are not removed from the gas. Therefore, it has some of the same drawbacks (for attaining very low emissions) as the IFP process.

ASR Sulfoxide Process --

The Sulfoxide process, marketed by Alberta Sulfur Research Ltd. (ASR), is likely to remove sulfur compounds from gas streams at better than 99.9%. This process uses an organic sulfoxide as a liquid-catalyst reaction medium for the Claus reaction. The process chemistry involves the initial formation of an adduct between the sulfoxide and the H_2S, which in turn forms a complex with the other sulfur compounds present. The oxidation-reduction reactions occur in this complex to yield H_2O, CO_2 and sulfur.

Typical low concentrations of H_2S and SO_2 in tail-gas streams can be reacted virtually to completion. A most-important factor in the process is its ability to convert COS and CS_2 to CO_2 and sulfur. The process can convert better than 70% of the COS and CS_2 present to sulfur.

Dry-Extension Processes

SNPA/Lurgi Sulfreen Process --

This process is essentially an extension of the Claus process, except that H_2S and SO_2 are made to react at temperatures below the sulfur dew point of the reaction gas mixture:

$$2H_2S + SO_2 \rightarrow 3S + 2H_2O + 35 \text{ Kcal.}$$

Since equilibrium conversion becomes more complete as the temperature is lowered, substantially higher sulfur recovery is possible than in a normal Claus plant. The reaction takes place in the presence of a catalyst, either alumina or special activated carbon. Sulfur formed is adsorbed on the catalyst which eventually becomes saturated, requiring periodic regeneration by desorption of the sulfur with hot gas. The process reduces sulfur compounds in the gas stream to a minimum, as the catalyst acts as a very effective adsorbent for liquid sulfur. COS and CS_2 are not affected.

An alternate of the Sulfreen process involving a two-stage treatment can provide overall recoveries exceeding 99%. A two-stage Sulfreen unit consists of two catalytic beds in series. In the first bed H_2S and SO_2 form sulfur according to the Claus reaction; however, the ratio of H_2S/SO_2 is adjusted in such a manner that essentially all of the SO_2 is consumed and the effluent gas contains only H_2S. After addition of air to the first stage effluent, H_2S is oxidized directly to sulfur in the second stage.

Amoco CBA Process --

The Amoco Production Co. "cold-bed" absorption (CBA) process is very similar to the Sulfreen process, except CBA uses a process stream indigenous to the Claus plant to accomplish regeneration of the sulfur-fouled catalyst beds in the CBA reactors. As with Sulfreen, the CBA process is basically an extension of the Claus reaction over a cool bed, 400-420°K (260-300°F), of conventional Claus catalyst. Amoco claims overall recoveries (Claus + CBA) of 98-99.5%.

Dry-Oxidation Processes

Shell SFGD Process --

Shell Oil Co. developed its Shell flue-gas-desulfurization (SFGD) process mainly for SO_2 recovery from stacks, but it can also be applied for Claus tail-gas stream cleanup. In this version of the SFGD process, the tail-gas is first incinerated to oxidize all sulfur compounds to SO_2. The gases are cooled somewhat to about 670°K (750°F) and are passed to a fixed bed of copper oxide-on-alumina to adsorb SO_2 from the gases. Two or more beds are used, and a swing-bed scheme is used to adsorb, regenerate, adsorb, etc. The SO_2 is desorbed from the adsorbent, at about 670°K (750°F), by addition of a hot reducing gas such as H_2 or H_2/CO mixture. The SO_2 may be used to produce sulfur, sulfuric acid, or other by-products.

Westvaco Process --

The Westvaco Corp. has developed an activated-carbon adsorption process for CO_2 removal from stack gases and Claus tail-gas. The Claus tail-gas is first incinerated at 810°K (1000°F) and diluted with air to bring the oxygen level to about 3.5 vol %. Then the gas is cooled in three stages to 360°K (200°F).

The gas then flows to a three-stage SO_2 adsorber. This is a continuous, countercurrent, multistage, fluidized-bed adsorber, with carbon particles flowing downward and tail gas flowing upward. The SO_2 is adsorbed from the gas as sulfuric acid by the activated carbon. The treated tail-gas leaves the adsorber containing less than 0.54 g/m^3 (200 ppm) SO_2. The SO_2 is released from the H_2SO_4/carbon in the regenerator, and is recycled back to the front of the Claus plant.

SNPA/TOPSOE Catalytic-Oxidation Process --

The Societe Nationale des Petroles d'Aquitaine (SNPA) of France and Halder Topsoe of Denmark have developed a wet-contact catalytic-oxidation process for treating Claus unit tail-gases.

In the SNPA/Topsoe Process, the Claus unit tail-gases are first incinerated to transform all sulfur into SO_2. The gases are cooled in a waste-heat boiler to 690°K (790°F). They are then passed through a converter containing a vanadium oxide-base catalyst. SO_2 is oxidized to SO_3, with a 95% yield.

The converted effluent gases are cooled in a boiler feedwater economizer to 570°K (570°F), and then go through an acid concentrator and on to the absorber, in which SO_3 is absorbed to form 80 wt % H_2SO_4. This "weak" acid is then sent to the concentrator, in which heat from the incoming gases evaporate part of the H_2O and a 94 wt % of H_2SO_4 is produced. The product acid is cooled and sent to storage.

The clean tail-gas from the absorber may be reheated or sent to the stack directly.

HEAVY HYDROCARBON STRIPPING

The final phase of the natural gas processing procedure is the recovery of the natural gas liquids: ethane, propane, butane, pentane, isobutane, and natural gasoline. There are both economic and operational reasons for the recovery of these components. They are worth more sold as a liquid than as a gas. The presence of small amounts of liquid in the pipeline can reduce the efficiency 10% since the pressure drop increases for a given flow rate as the liquids condense.(15) Also, the presence of heavy hydrocarbons in the feed entering a liquification unit can result in freeze-ups in heat exchangers or require the inclusion of additional liquid separators and special piping in the cold box to remove these materials from the process gas stream.

There are seven major processes for this gas separation step: absorption, refrigerated absorption, refrigeration, compression, adsorption, fractionation, and cryogenics/turboexpansion. These will be discussed in the following subsections.

Absorption

This process is used to remove natural gasoline, LPG (mixed ethane, propane and butane) from a wet natural gas. A flow diagram of the process is presented in Figure 18. The gas from the field passes through an absorber where an absorber oil removes the propane and heavier molecules. The residue gas, consisting chiefly of methane and ethane, is sold as natural gas. The enriched absorber oil goes to a stripper which separates the absorbed propane and heavier molecules from the absorption oil. The gas stream of propane and heavier molecules goes to the stabilizer where methane and ethane are driven off and recycled to the absorber. The remainder (bottoms) from the stabilizer goes to a splitter, a distillation column, where the LPG comes off as the overhead product while natural gasoline is the bottoms product.

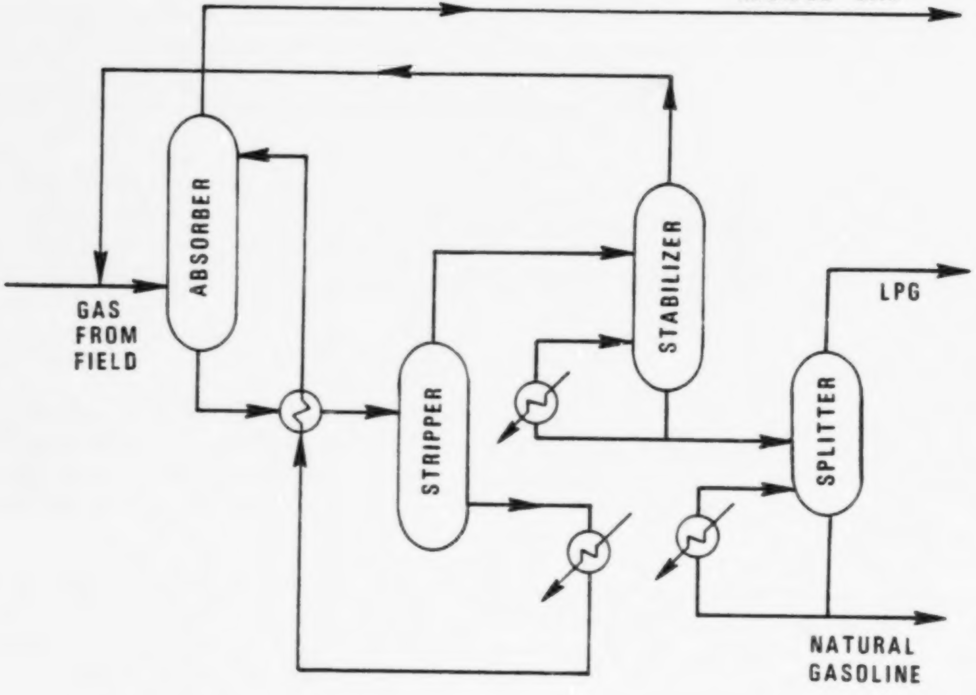

RESIDUE GAS
ABSORBER
STABILIZER
LPG
GAS
FROM
FIELD
STRIPPER
SPLITTER
NATURAL
GASOLINE

Figure 18: Absorption plant for natural gasoline.(10)

Refrigerated Absorption

A flow sheet of the refrigerated absorption process is presented in Figure 19.

In this process, the incoming gas is dehydrated to a 230°K (-40°F) dew point. This is accomplished by bringing the incoming natural gas into contact with triethylene glycol to absorb the water vapor. The glycol is regenerated by boiling off the water. At some plants, this water vapor leaves the process as steam and carries glycol at less than 8.1 kg/10^6 m^3 (0.1 lb/million ft^3) of gas processed into the atmosphere. After dehydration, the gas passes through two absorbers in series at 230°K (-40°F). All hydrocarbons except methane are absorbed by oil in the first absorber. A sponge oil regenerator recovers the hydrocarbons which were absorbed in the second stage absorption. These recovered hydrocarbons are mixed with the rich oil from the first stage absorption and fed to the primary demethanizer. The overhead gases from the demethanizer return to the absorber. The bottoms go to a rich-oil demethanizer where any remaining methane is removed as fuel gas. The rich oil then goes to a still where the balance of the absorbed hydrocarbons is distilled off, thus regenerating the first stage absorber oil. The overheads from this still are fractionated in two steps to produce ethane, propane, and a C_4+ hydrocarbon stream for sales.

High recoveries of ethane using this process are uneconomical, due to the large steam requirement and amount of oil that must be circulated. Yet it is a favorable process for LNG recovery at remote locations since the refrigerant (propane) and the absorption oil (natural gasoline) can be recovered from the feed gas itself.

Refrigeration Process

The amount of heavy hydrocarbon vapor that can be held at saturation by natural gas decreases with decreasing temperature and/or increasing pressure. Increased recovery of LPG and natural gasoline can be achieved in a compressor plant if refrigeration is used in place of cooling water in the compressed gas coolers.

A refrigeration plant is shown in Figure 20. In this process, the inlet gas is dried to a dew point of 190°K (-120°F), using molecular sieve beds. Water vapor is adsorbed on these beds which are used in parallel, arranged so that one is on-stream while the other is being regenerated. Regeneration is accomplished by means of heat and a stream of hot gas. The hot gas from the bed being regenerated is cooled to condense the water and is then fed to the operating bed. The dry gas from the molecular sieve is then passed through a heat exchanger where it is cooled to 236°K (-35°F). Liquids which condense are removed in a separator. The gas from the separator is cooled to 180°K (-135°F) and passes through a second separator where more condensed liquids drop out. The gas from this separator then passes back through the two heat exchangers countercurrent to the incoming gas, where it cools the incoming feed gas. The liquids from the two separators are fed to five distillation columns in a series where methane, ethane, propane, isobutane, normal butane and natural gasoline are recovered as separate products.

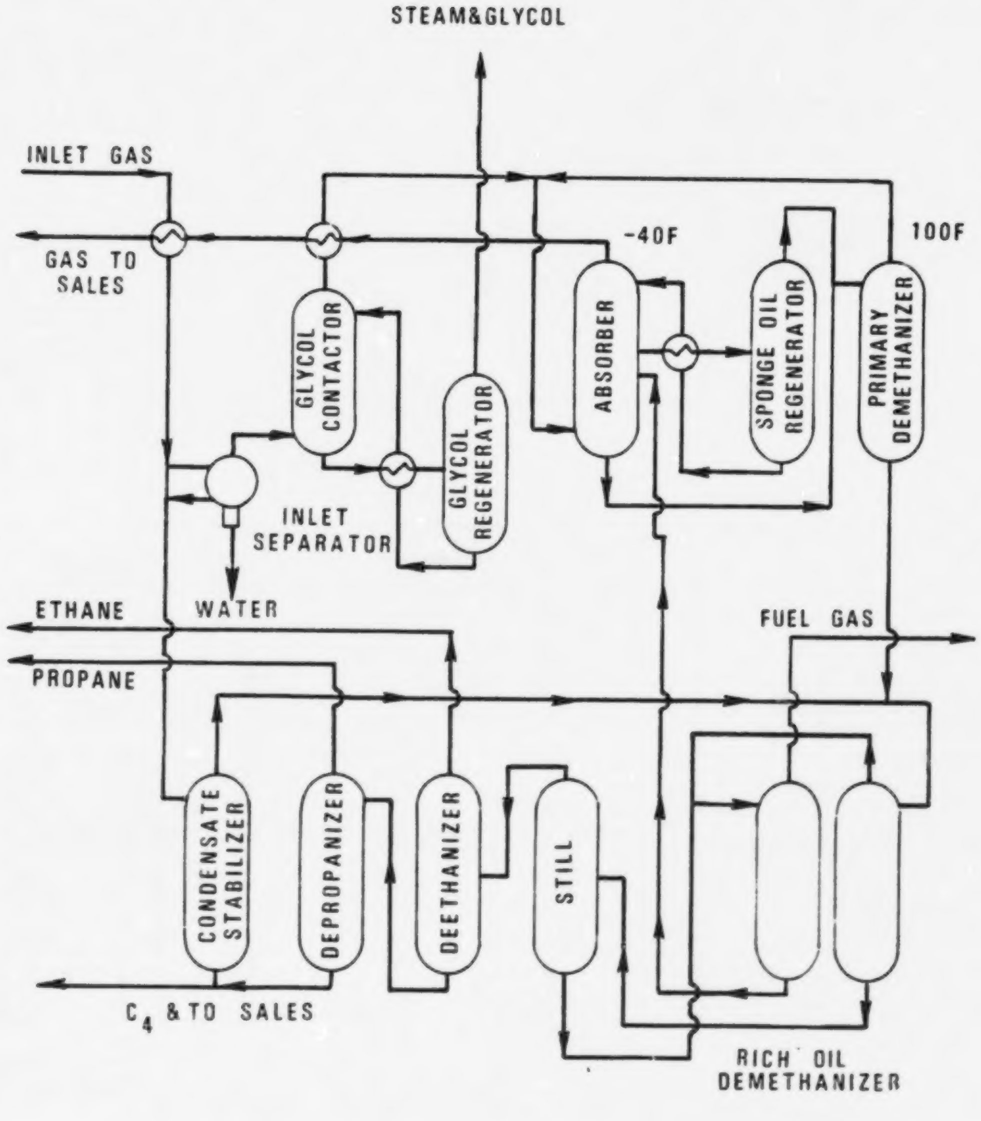

STEAM&GLYCOL
INLET GAS
GAS TO SALES
-40F
100F
GLYCOL CONTACTOR
GLYCOL REGENERATOR
ABSORBER
SPONGE OIL REGENERATOR
PRIMARY DEMETHANIZER
INLET SEPARATOR
WATER
ETHANE
PROPANE
FUEL GAS
CONDENSATE STABILIZER
DEPROPANIZER
DEETHANIZER
STILL
C_4 & TO SALES
RICH OIL DEMETHANIZER

Figure 19: Flow diagram of the refrigerated absorption process. (10)

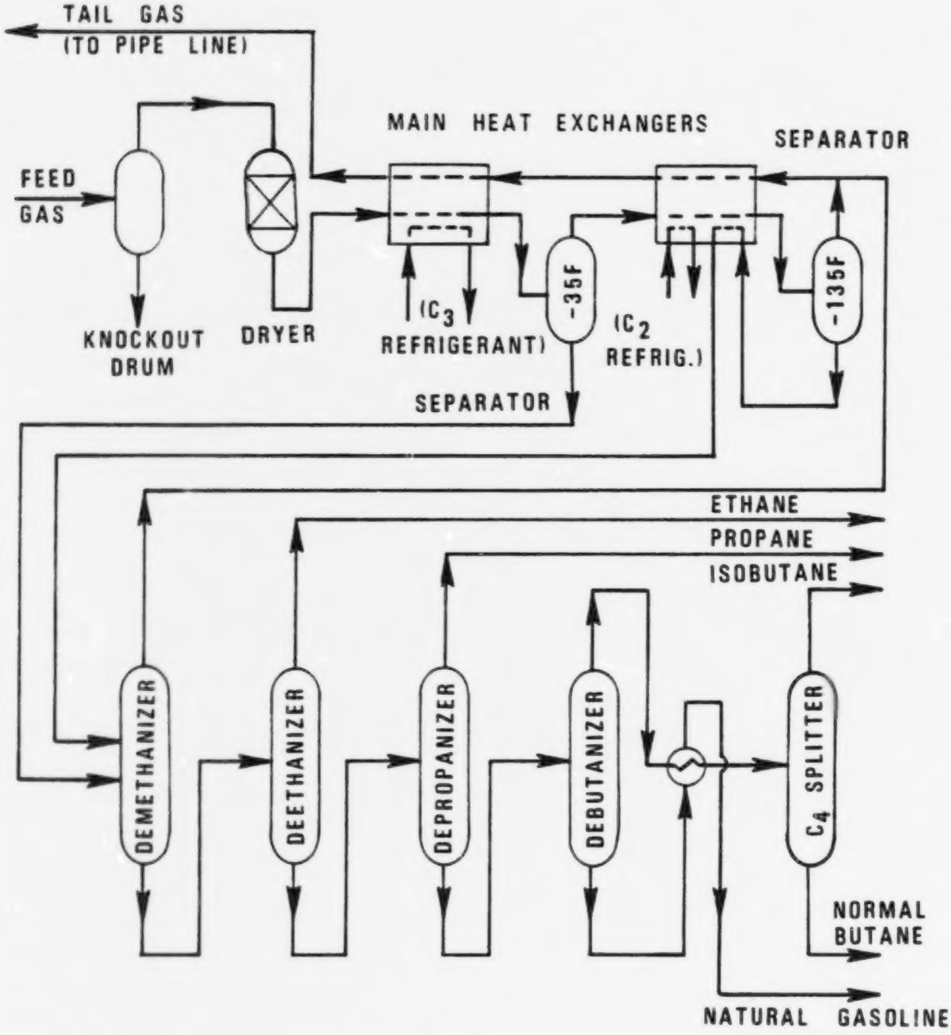

TAIL GAS
(TO PIPE LINE)
FEED GAS
KNOCKOUT DRUM
DRYER
MAIN HEAT EXCHANGERS
(C3 REFRIGERANT)
-35F
SEPARATOR
(C2 REFRIG.)
SEPARATOR
-135F
ETHANE
PROPANE
ISOBUTANE
DEMETHANIZER
DEETHANIZER
DEPROPANIZER
DEBUTANIZER
C4 SPLITTER
NORMAL BUTANE
NATURAL GASOLINE

Figure 20: Flow diagram of the refrigeration process.(13)

Compression

Natural gas is often transported through high pressure pipelines as a matter of economy. Where the gas is produced at low pressure, the gas must first be compressed. Although natural gas is seldom compressed solely for the purpose of LPG or natural gasoline recovery, significant amounts of these products are recovered from compressor stations. Under pressure, the heavy hydrocarbons are condensed and separated from the natural gas. Since the increase in pressure per stage is limited by practical considerations, several stages of compression may be needed to reach the required pressure.

Figure 21 is a flow chart for a typical two-stage compressor station. Gas enters through an inlet scrubber or knockout drum to remove entrained liquid. The gas is compressed in the first stage cylinder, cooled by a cooling water exchanger and sent to the first stage accumulator. Water and hydrocarbons are separated from the gas under liquid level and interface level control. The liquid hydrocarbons are sent to a distillation unit for recovery of LPG and natural gasoline. The gas is then compressed in the second-stage in a similar manner.

Adsorption

The flow sheet of this process (Figure 22) shows the steps used to obtain a natural gas product and a mixed hydrocarbons product. The resulting liquids product is fed to a fractionation process.

The basic process consists of two or more beds of activated carbon. The beds are used alternately, with one or more beds on-stream while the others are being regenerated. The activated carbon adsorbs all hydrocarbons except methane. The bed is regenerated by means of heat and steam, which remove the adsorbed hydrocarbons as a vapor. This vapor is then condensed permitting the water to be separated from the liquid hydrocarbons.

Other adsorbants which are used include alumina, silica gel, molecular sieve, zeolites, and charcoal.

Cryogenics/Turbo-Expansion

Cryogenic or turbo-expansion gas processing uses temperatures in the 140°-200°K (-100 to -200°F) range. The lower temperatures enable greater percentages of ethane and propane to be extracted. There are two methods of lowering the gas temperature using pressure drop and heat exchange. The first is by a choke of throttling calorimeter expansion. In the process of expanding across the control valve (choke), the temperature of the gas is lowered. The second is the expander-cycle process which uses a "reverse running" centrifugal compressor or turbine. In the process of expansion through the turbine, the gas works on the wheel of the turbine; thus, useful work is produced which is usually used for recompression.

Figure 23 presents the basic expander cycle. The gas must first be dehydrated to a dew point at least as low as 200°K (-100°F) by any one of the dehydration processes.

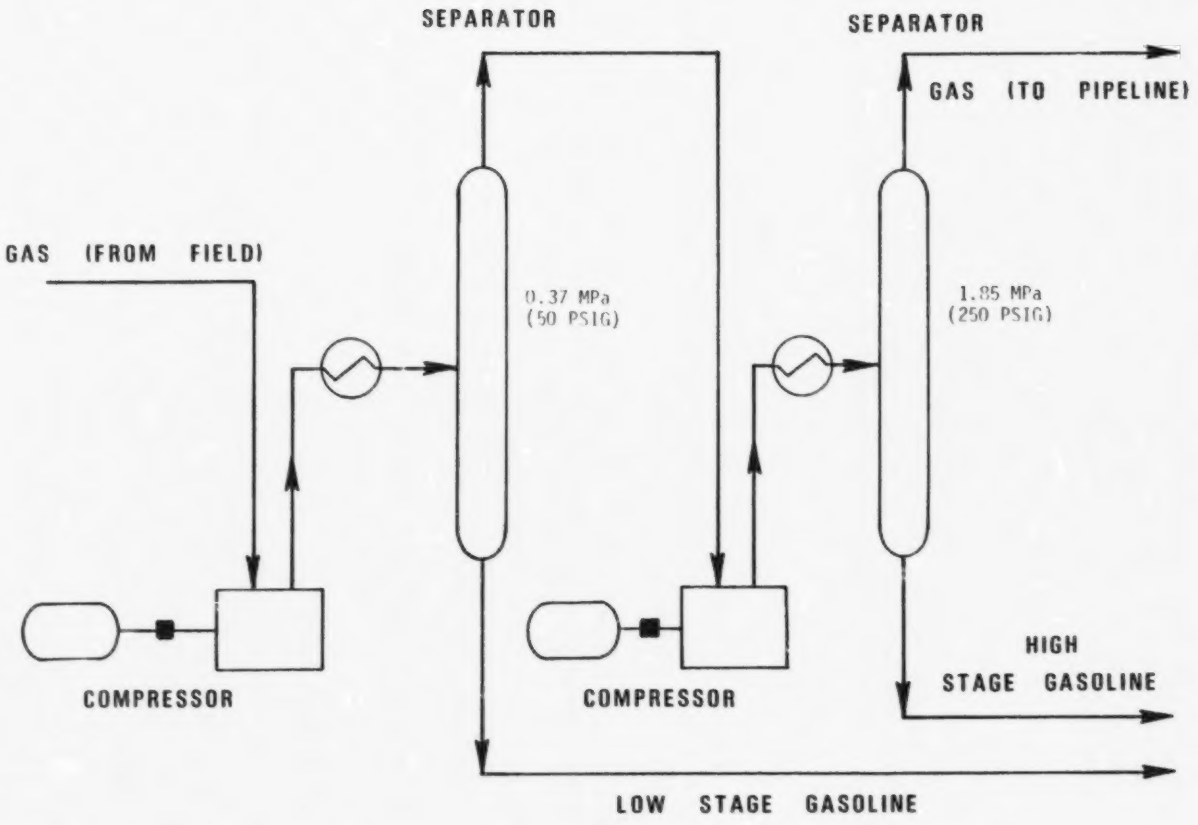
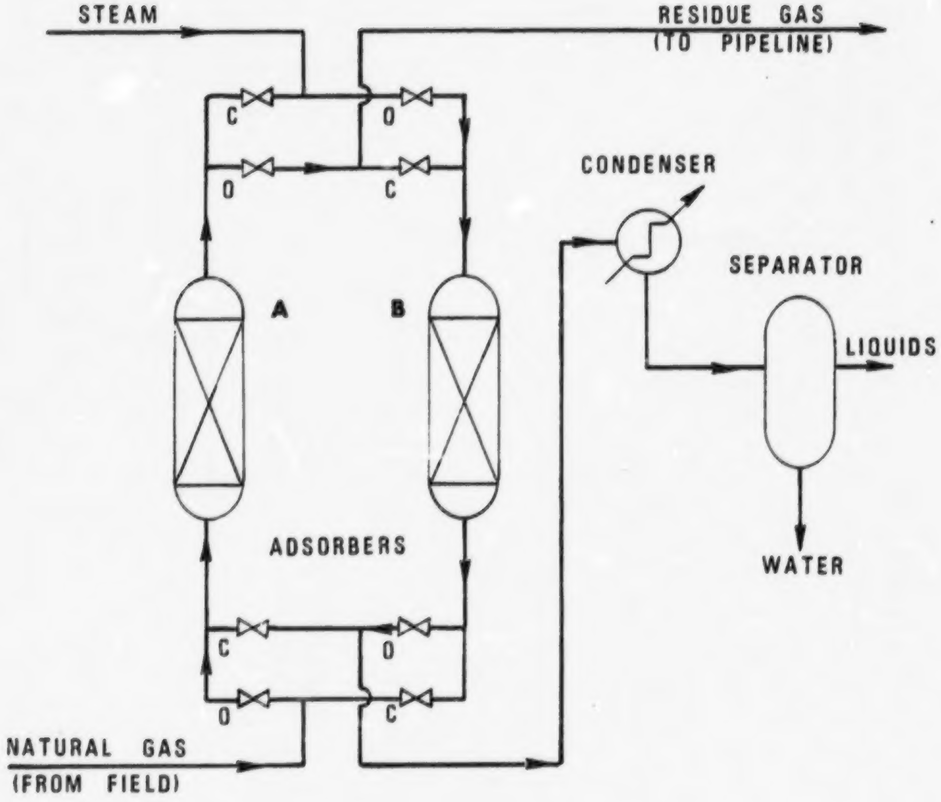
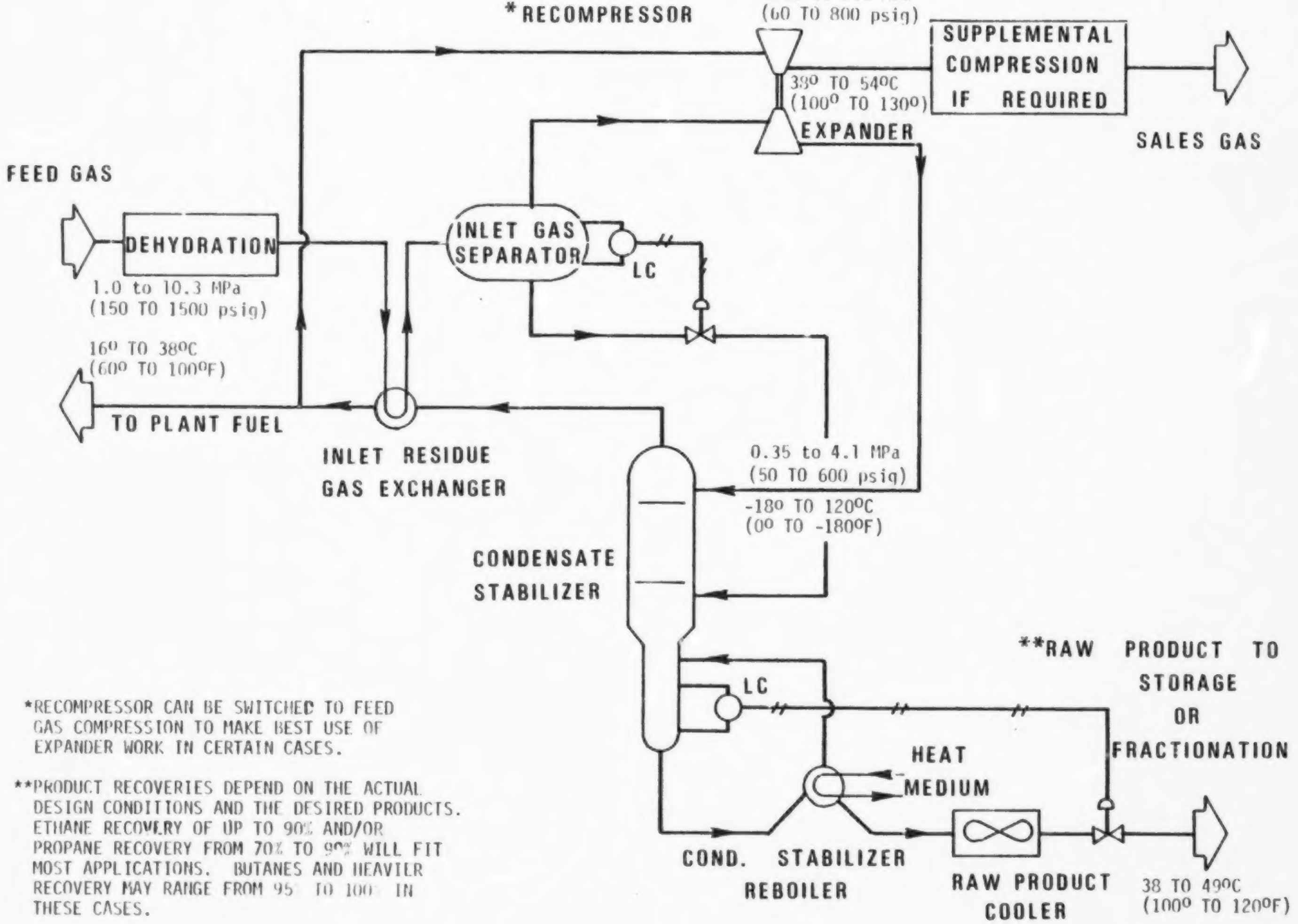

SEPARATOR
SEPARATOR
GAS (TO PIPELINE)
GAS (FROM FIELD)
0.37 MPa
(50 PSIG)
1.85 MPa
(250 PSIG)
COMPRESSOR
COMPRESSOR
HIGH
STAGE GASOLINE
LOW STAGE GASOLINE

Figure 21: Flow diagram of the compression process.(13)


STEAM
RESIDUE GAS (TO PIPELINE)
C
O
O
C
CONDENSER
SEPARATOR
A
B
LIQUIDS
ADSORBERS
WATER
C
O
O
C
NATURAL GAS (FROM FIELD)

NOTE: FLOWS AND VALVE POSITIONS ARE SHOWN FOR ADSORBER 'A' ON STREAM AND ADSORBER 'B' ON REGENERATION.

Figure 22: Flow diagram of adsorption process.(10)


*RECOMPRESSOR
0.41 to 5.5 MPa
(60 TO 800 psig)
SUPPLEMENTAL COMPRESSION IF REQUIRED
33° TO 54°C
(100° TO 130°)
EXPANDER
SALES GAS
FEED GAS
DEHYDRATION
1.0 to 10.3 MPa
(150 TO 1500 psig)
16° TO 38°C
(60° TO 100°F)
INLET GAS SEPARATOR
LC
TO PLANT FUEL
INLET RESIDUE GAS EXCHANGER
0.35 to 4.1 MPa
(50 TO 600 psig)
-18° TO 120°C
(0° TO -180°F)
CONDENSATE STABILIZER
LC
**RAW PRODUCT TO STORAGE OR FRACTIONATION
HEAT MEDIUM
COND. STABILIZER REBOILER
RAW PRODUCT COOLER
38 TO 49°C
(100° TO 120°F)

*RECOMPRESSOR CAN BE SWITCHED TO FEED GAS COMPRESSION TO MAKE BEST USE OF EXPANDER WORK IN CERTAIN CASES.

**PRODUCT RECOVERIES DEPEND ON THE ACTUAL DESIGN CONDITIONS AND THE DESIRED PRODUCTS. ETHANE RECOVERY OF UP TO 90% AND/OR PROPANE RECOVERY FROM 70% TO 90% WILL FIT MOST APPLICATIONS. BUTANES AND HEAVIER RECOVERY MAY RANGE FROM 95% TO 100% IN THESE CASES.

Figure 23: Flow diagram of the expander cycle. (16)

After dehydration, the feed is chilled down with cold residue gas. A large amount of liquid is produced which is separated before entering the expander. This liquid flows to the condensate stabilizer. Gas from the separator flows to the expander. The expander exhaust stream typically contains up to 20 wt % liquid. This two-phase mixture flows to the top section of the stabilizer which separates the liquid and gas. The liquid stream flows down the tower and acts as reflux. Cold gas from the stabilizer cools the feed and is then compressed by the expander-driven compressor. Supplemental compression is supplied, if required.

FUTURE PROCESSING TRENDS

Future processing trends tend to fall into several main areas: low temperature hydrocarbons recovery, increasing automatic and less manual process control, energy conservation and construction of small modular plants which can be moved from site to site. Of these, only the first is actually concerned with new processing methods. The others are related to current process improvement.

The main processing trend is away from the traditional absorption process to the cryogenic and expander plants for hydrocarbons recovery. Table 9 presents a tabulation and comparison of the U. S. gas-products-extraction processes used in 1976 and 1977. As can be seen, the expander and cryogenic processes show the greatest use increase by a wide margin. The low temperature processes require less fuel and recover greater percentages of ethane and butane. These parameters are compared in Table 10 with those of the absorption process.

The second area of future trends is the area of energy conservation and automatic process control. The growing shortage of domestic energy requires all industry to try to optimize energy usage. This is directly tied to the trends of turbo-expansion which requires less energy than absorption and computer use which optimizes the processes more accurately than heretofore possible.

Another innovation being developed is the construction of portable gas-processing plants. Portable gas-processing plants are also coming into use because of the energy demand. As the demand for energy continues to grow, the feasibility of processing smaller volumes of natural gas increases substantially. The relatively short fabrication and installation time for the current generation of small, portable gas processing plants enables them to be quickly set up so that small oil and gas fields can be developed and produced efficiently and economically.

TABLE 9

COMPARISON OF DOMESTIC GAS PRODUCTS EXTRACTION PROCESSES (17)

	Number of Installations			
Process	1976	1977	Change	% Change
Refrigerated absorption	337	317	-20	-5.9
Refrigeration	180	163	-17	-9.4
Absorption	131	125	- 6	-4.6
Expander	13	82	+69	+530.8
Adsorption	56	55	- 1	-1.8
Cryogenic	17	42	+25	+147.1
Compression	14	15	+ 1	+7.1
Fractionation	4	7	+ 3	+75.0
Total	752	806	+54	

TABLE 10

COMPARISON OF SEVERAL OPERATION PARAMETERS FOR ABSORPTION VS. CRYOGENIC PLANTS (18)

	Type of Plant	
Parameter	Absorption	Cryogenic
Temperature	240-300°K (-20 - 90°F)	170°K (-150°F)
Fuel Consumption	2 - 4%	1 - 2%
Ethane Recovery	0 - 35%	60 - 90%
Propane Recovery	50 - 90%	92 - 98%

SECTION 6

AIR POLLUTION ASPECTS OF THE DOMESTIC GAS PROCESSING INDUSTRY

Quantitative information on natural gas processing emissions is very limited. Emission inventories for Texas and Louisiana, the states with over 60% of the total number of plants in the U.S., were the most comprehensive information sources found. The National Emissions Data System (NEDS) does not have any emissions information for natural gas plants. It was intended that a comparison of gas industry emissions estimates with NEDS data for other industry categories could provide a perspective of this industry's contribution to the total domestic emissions load. However, the NEDS data is based on major sources, those emitting more than 100 tons per year of a criteria pollutant. The estimates of gas processing industry emissions are based on data for all gas processing plants, not just those emitting more than 100 tons per year. Because of this dissimilarity between sources of information, comparing natural gas processing industry emissions with a range of other industrial categories within this scope of work was not possible. The evaluation of the air pollution aspects of the industry was limited to providing the following:

- an estimate of the industry's emissions
- a summary of the Texas and Louisiana emission inventories
- a discussion of in-plant emission sources and control techniques currently employed in the industry.

AIR EMISSIONS IN THE NATURAL GAS PROCESSING INDUSTRY

There are four major pollutants associated with the natural gas processing industry:

- Sulfur Dioxide (SO_2)
- Hydrocarbons (HC)
- Hydrogen Sulfide (H_2S)
- Glycol

Sulfur Dioxide

Sulfur dioxide is a significant pollutant emission associated with sour gas processing plants. Historically, field flares and waste gas venting at field sites and processing plants were major point sources. However, air pollution regulations and increased market value for natural gas products has led to a remarkable decrease in venting and flaring since 1970 (75% reduction). Flares and vents are generally used only as safety devices.

Sulfur dioxide is a combustion byproduct of H_2S and is largely emitted from H_2S flares in processing plants that do not have sulfur recovery facilities. Sulfur recovery facilities, such as Claus plants, generally have tail gas cleanup process which can routinely reduce SO_2 emissions to 1.4 g/m^3 (500 ppm).

The total estimated SO_2 emissions from the natural gas processing industry in 1976 were approximately 4900 ktpy (5400 thousand short tons per year (Tpy)). (See Table 11.)

As these data show, SO_2 emissions have decreased approximately 20% between 1969 and 1976. This is primarily due to the addition of substantial, new sulfur recovery capacity over the last seven years. A significant element affecting these estimates is the average industry-wide utilization for Claus plants which we set at 65% to be consistent with prior work.(10) However, plants without sulfur recovery do remain the most significant contributors in the industry, irrespective of the utilization factor (within practical limits). We have assumed a Claus plant sulfur recovery efficiency of 90% to be consistent with prior work. However, most plants in Texas and Louisiana are required by law to be 94-97% efficient.(13) We have also assumed a 99% sulfur recovery efficiency for Claus plants with tail-gas cleaning.

It is likely that future SO_2 emissions will stabilize or diminish against rising production as old fields phase out of production and new ones are developed. It is likely that the new processing plants serving these fields will have sulfur recovery facilities whereas it is unlikely that older plants will be retro-fit.

As the data in Table 12 show, the natural gas processing industry could account for up to 20% of the total estimated sulfur dioxide emissions in the United States in 1972.

Table 13 shows an estimate of the emissions from the fuel burning sources associated with the natural gas industry (lease, plant and pipeline turbines). These emissions with the exception of NO_x appear to be minor.

Hydrocarbons

The second most important pollution associated with natural gas processing is miscellaneous hydrocarbons. Since the primary objective of gas processing is to provide maximum yields of valuable products, hydrocarbon losses are

TABLE 11

COMPARISON OF ESTIMATES FOR SULFUR DIOXIDE EMISSIONS FROM PROCESS SOURCES IN THE NATURAL GAS PROCESSING INDUSTRY

1969 vs. 1976

	1969 Mtpy ($x10^6$ Tpy)	1976 Mtpy ($x10^6$ Tpy)
Sulfur production in Claus plants*	0.78 (0.87)	1.2 (1.3)
Sulfur dioxide emissions, Claus plant		
all without tail gas clean up**	0.15 (0.17)	0.23 (0.26)
all with tail gas clean up***	0.015 (0.017)	0.023 (0.026)
Field venting and flaring volume(2)	14.7 Gcum (526×10^6 ft^3)	3.7 Gcum (132×10^6 ft^3)
Sulfur dioxide emissions, Field vents and flares†	0.16 (0.18)	0.036 0.04
Sulfur dioxide emissions, without sulfur recovery plants††	6.7 (7.4)	5.3 (5.8)
Sulfur in marketed gas @SO$_2$	0.003 (0.003)	0.003 (0.003)
Total estimated sulfur dioxide emissions from process sources	6.9-7.1 (7.6-7.8)	5.4-5.5 (5.9-6.1)

---

*Industry capacity: 1969: 1200 kt/yr,(10) 1976: 1800 kt/yr;(19) 65% utilization.

**Assume: 90% sulfur recovery(10).

***Assume: 99% sulfur recovery.

†Assume: 80% is flared,(10) 0.5 Mol% sulfur in raw gas.(10)

††Assume: 100% flared product gas contains 0.5 Mol% sulfur and 95% conversion to SO$_2$.

TABLE 12

COMPARISON OF SO_2 EMISSIONS FROM ALL SOURCES

	kt/year (10^6 T/year)
Natural gas industry, 1972*	5500-5600 (6.1-6.3)
CEQ Data - 1972(13)	
All industrial processes	4600 (5.1)
Stationary sources using fuel combustion	23900 (26.3)
Solid waste disposal	900 (0.1)
Miscellaneous	900 (0.1)
Total (except SO_2 from natural gas)	29600 (32.6)

---

*prorata 1969-1976

TABLE 13

ESTIMATE OF EMISSIONS FROM NATURAL GAS PROCESSING, 1976 PLANT AND PIPE LINE POWER GENERATION EQUIPMENT(2),(20)

Pollutant	Emissions ktpy
Particulate	5-15
Sulfur Oxides @SO_2	0.6
Carbon Monoxide	13.0
Hydrocarbons @CH_4	3.0
Nitrogen Oxides @NO_2	120-230

minimized by routine maintenance and plant design consistent with good engineering practice. Major sources of hydrocarbon emissions are vents, and storage facilities.

The total hydrocarbon emissions from the natural gas processing industry in 1976 (latest year for which data are available) are estimated to be an average of 4,400 tpd (4,900 Tpd) by venting and flaring. An additional 28,600 tpd (31,500 Tpd) is unaccounted for in the entire production, distribution and final usage network. These estimates are based on the data in Table 2 and the following assumptions:

- 20% of "vented and flared" gas is vented.
- Flaring of the remaining gas reduces the hydrocarbon emissions by 90%.
- All "unaccounted for" gas is lost to the atmosphere by miscellaneous fugitive sources.
- The emitted hydrocarbons have an average density of 1.6 kg/m^3 (0.1 lb/cf) (mainly methane, ethane, propane and butane).

As data in Table 2 show, an substantial decrease in 'venting and flaring', from 2% to 0.6% of the total gross production, has occurred from 1970 to 1976. It is logical to assume that some additional improvement will be made in curtailing venting and flaring as the value of these products increase. Losses "unaccounted for" have remained consistently at 10% of total production since 1970. We presume these losses, which are a substantial part of the total of 33,000 tpd (36,400 Tpd) are fugitive emissions from miscellaneous sources such as flanges, pumpseals, pressure safety relief valves, etc.

Lease plant and pipeline power generating equipment contributes 2,700 tpy (3,000 Tpy) of hydrocarbons (see Table 13).

No information has been found that could be used to differentiate reactive and nonreactive components of the total hydrocarbon emissions from this industry. A typical natural gas as extracted from the well may contain up to 90-95% methane, ethane, carbon dioxide, hydrogen sulfide and water. The balance is primarily paraffinic.

Hydrogen Sulfide

We were not able to find sufficient information to develop a reliable estimate for total industry-wide hydrogen sulfide emissions. Others have estimated these emissions as approximately 47 metric tons per day (52 Tpd).(10)

Glycol(10)

To estimate the amount of triethylene glycol (TEG) emitted to the atmosphere, the following information was required:

- the number and capacity of plants using glycol dehydration and which vent the water vapor produced by the dehydration step, and
- the quantity of triethylene glycol consumed as a function of gas processed.

This information was not readily available so the following assumptions were made:

- 25% of all gas produced in the U.S. is dehydrated with TEG.
- All plants vent the dehydration water.
- 50% of glycol losses are entrained with vented dehydration water. The other half is entrained in the gas stream.

Maximum glycol losses are estimated as 1.06 kg/Mm^3 (0.1 gallons/mcf) which leads to a daily emission rate of 6.3 tpd (7 Tpd).(10)

TEXAS EMISSION INVENTORY

An emission inventory was obtained from the Texas Air Control Board in Austin, Texas. The inventory contains quantified emissions data for 1973. The data are broken down into natural gas processing plants, alphabetically by county, for each of the state's twelve regions. The data includes the yearly quantities of NO_x, SO_x, hydrocarbons (HC), CO, particulates (P), and H_2S emitted from all 418 Texas plants.

Space limitations prevent listing the emissions for each of the 418 plants. However, the results are summarized in Table 14.

As can be seen from the tables NO_x and SO_x are the emissions produced in the greatest quantity by Texas natural gas processing plants. Hydrocarbons rank third at about 40 percent of the SO_x level. The other three pollutants are of minor importance.

Table 15 shows the contribution to sulfur and nitrogen oxides and hydrocarbon air pollution in Texas by major industries. The natural gas industry is the most significant in sulfur and nitrogen oxides and the third highest in hydrocarbons as reported in the 1973 Texas Emission Inventory.

TABLE 14

TEXAS EMISSION INVENTORY SUMMARY FOR NATURAL GAS PROCESSING PLANTS
1973 DATA

Region	No. of Plants	Emissions in Metric Tons Per Year (Short Tons Per Year)					
		NO_x	SO_x	HC	CO	Part	H_2S
1	43	13204 (14555)	252 (278)	2457 (2708)	4.5 (5)	38 (42)	--
2	47	39317 (43340)	24902 (27450)	16174 (17829)	38 (42)	207 (228)	763 (841)
3	2	66 (73)	5401 (5954)	31 (34)	0.9 (1)	5.4 (6)	--
4	18	5211 (5744)	-- --	2898 (3195)	2.7 (3)	13.6 (15)	--
5	56	41714 (45982)	2425 (2673)	22132 (24396)	44 (48)	216 (238)	9 (10)
6	133	95831 (105636)	170888 (188372)	27039 (40828)	141 (155)	494 (544)	8856 (9762)
7	40	33667 (37111)	72 (79)	16987 (18725)	64 (71)	308 (339)	--
8	22	4382 (4830)	2612 (2879)	2685 (2960)	3.6 (4)	27 (30)	--
9	11	2223 (2450)	11480 (12655)	1676 (1848)	5.4 (6)	34 (37)	117 (129)
10	7	2238 (2467)	--	659 (726)	1.8 (2)	16 (18)	--
11	0	--	--	--	--	--	--
12	39	15743 (17354)	54971 (60595)	9338 (10293)	25 (28)	142 (157)	214 (236)
State Totals	418	253597 (279542)	273004 (300935)	112076 (123542)	331 (365)	1500 (1654)	9959 (10978)

TABLE 15

POINT SOURCE EMISSIONS FROM INDUSTRIAL PROCESSES
TEXAS EMISSION INVENTORY -1973
POLLUTANT IN METRIC (SHORT) TONS PER YEAR

Industry	Sulfur Oxides	Nitrogen Oxides	Hydrocarbons
Natural Gas Processing	(300,935) 272,957	(279,542) 253,553	(123,542) 112,076
Petroleum Industry	(253,309) 229,759	(92,484) 83,886	(330,450) 299,728
Chemical Manufacturing	(153,774) 139,478	(12,767) 11,580	(498,814) 452,439
Primary Metal	(133,049) 120,679	(6,950) 6,304	(2,672) 2,424
Secondary Metals	(59,867) 54,301	(443) 402	(296) 268
Mineral Products	(12,614) 11,441	(3,415) 3,098	(2,134) 1,936
Wood Products	(5,177) 4,696	(678) 615	(355) 322
Food/Agriculture	(56) 51	(172) 156	(37) 34
Metal Fabrication	0	0	(6) 5
Leather Products	0	0	0
Textile Manufacturing	0	0	0

LOUISIANA EMISSION INVENTORY

A visit was made to the Louisiana Air Control Commission in New Orleans, Louisiana, to obtain more detailed plant emission information than was possible to get with a general emission inventory such as that obtained from Texas. Each of the natural gas processing plants in the State of Louisiana is required to complete an emission inventory questionnaire. These questionnaires provide information on total plant consumption, products, and emissions, as well as the charging rates and emissions for each individual emission source within the plant. The visit to New Orleans produced total plant emission information for 52 plants and detailed individual point source emission information for 18 of them. With this detailed information, it was possible to determine what types of heaters and engines are in use and the emissions they produce as well as the emissions associated with flares and storage tanks.

Table 16 presents a summary of the total plant emissions for 52 Louisiana gas processing plants for the year 1975 along with the processes used for heavy hydrocarbon stripping and the total plant throughput. It can be seen that refrigerated absorption is most commonly used for hydrocarbons recovery with approximately 75 percent of the plants using this process alone or in combination with other processes. NO_x emissions predominate in the 52 plant sample with CO emissions being secondary. However, high CO levels are noted in only three plants (42, 44, and 47) with the remaining plants showing much lower levels. The hydrocarbon level is about 30 percent of the NO_x level which is similar to that noted in Texas. The big difference is the low SO_x level in Louisiana compared with the high level in Texas. This could be due to the differences in raw gas quality. There does not appear to be any relationship between total plant throughput and total plant emissions as can be seen in Figures 24 and 25. Figure 24 is a plot of total plant NO_x emissions versus throughput and Figure 25 is a plot of hydrocarbons emission versus throughput.

Table 17 through 20 present the charging rates, emissions, and emission rate for flares, storage tanks, engines, and heaters, respectively. Emissions from flares are mainly NO_x with the maximum noted being 5 tpy. Emissions from storage tanks, which arise from breathing and working (i.e., filling) losses are typically only 3.0 tpy (3.3 Tpy) from plant #13's scrubber oil tank. Engine emissions are NO_x, SO_x, and hydrocarbons with NO_x predominating by far. Several plants utilize engines that produce about 635 t (700 T) of NO_x per year. Heater emissions include all five pollutants, but only NO_x is prevalent with a maximum of 172 tpy (190 Tpy) from a waste heat boiler.

An examination of the emission rates presented in the four tables reveals that for the majority of the plants, the emission levels are derived from the charging rates using emission factors obtained from AP-42 emission factors. Tables 21 and 22 present these emission factors. This means that the values presented for the emission levels are only estimates and are not based on actual measurements. The total plant emissions are merely a function of the number of engines, heaters, flares, and storage tanks along with their charging rates and are not based on plant-wide measurements.

TABLE 16

LOUISIANA EMISSION INVENTORY SUMMARY FOR THE NATURAL GAS PROCESSING INDUSTRY 1975 DATA

Number	Process Used[1]	Throughput hm^3/d (MMcfd)		Emissions in Metric Tons Per Year[1] (Short Tons)					
		1975[2]	1976[3]	NO_x	SO_x	HC	CO	Part.	H_2S
1	2	2.4 (84.9)	1.9 (66.0)	816 (899)		1.8 (2)	0.9 (1)	0.9 (1)	
2	2	5.4 (189.6)	5.4 (190.0)	2206 (2432)		5.4 (60)	2.7 (3)	2.7 (3)	
3	2	1.0 (34.8)	0.7 (26.0)	353 (389)		1.8 (2)	0.9 (1)	0.9 (1)	
4	2	1.6 (57.0)	1.2 (44.0)	251 (277)		0.9 (1)	1.8 (2)	1.8 (2)	
5	2	1.2 (41.4)	0.9 (31.0)	816 (899)		1.8 (2)	0.9 (1)	0.9 (1)	
6	2	1.0 (34.2)	0.8 (28.0)	170 (187)		0.9 (1)	0.9 (1)	0.9 (1)	
7	5	0.3 (10.3)	0.2 (7.1)	3.6 (4)			0.9 (1)		
8	1	0.25 (9.0)	0.2 (7.1)	26 (29)		17 (19)	2.7 (3)	1.8 (2)	
9	3	--	0.01 (4)	0.9 (1)		3.6 (4)			
10	2	2.2 (76.0)	2.2 (79.0)	160 (176)		93 (103)	1.8 (2)		
11	2,6	22.3 (788.3)	19.0 (671.5)	404 (445)	0.9 (1)	56 (62)	0.9 (1)	24 (26)	
12	2,5	7.2 (254.1)	7.3 (258.9)	734 (809)	0.9 (1)	111 (122)	0.9 (1)	22 (24)	
13	2	--	10.8 (380.0)	227 (250)	2.7 (3)	19 (21)	56 (62)	12 (13)	
14	2	--	2.2 (76.0)	142 (157)	0.9 (1)	7.2 (8)	14 (15)	1.8 (2)	
15	2	0.4 (15.0)	--	26 (29)		29 (32)			
16	2	--	2.5 (89.4)	60 (66)			3.6 (4)	1.8 (2)	
17	2	1.4 (50.5)	1.3 (46.0)	403 (444)		140 (154)	49 (54)	2.7 (3)	
18	2	1.6 (57.4)	1.6 (57.4)	496 (547)		198 (218)	77 (85)	4.5 (5)	
19	1	--	6.1 (215.0)	320 (353)		330 (364)	29 (32)	3.6 (4)	

TABLE 16 (Continued)

Number	Process Used[1]	Throughput hm³/d (MMcfd)		Emissions in Metric Tons Per Year[1] (Short Tons)					
		1975[2]	1976[3]	NO_x	SO_x	HC	CO	Part.	H_2S
20	2,7	14.6 (515.1)	11.8 (417.)	409 (451)	0.9 (1)	48 (53)	5.4 (6)	8.1 (9)	1.8 (2)
21	-	--	--	23 (25)	4.5 (5)	240 (265)	185 (204)	13 (14)	
22	7	14.2 (500.0)	9.8 (346.0)	605 (667)		48 (53)	1.8 (2)	3.6 (4)	
23	2	13.8 (488.5)	12.9 (457.0)	365 (402)		154 (172)	37 (41)	44 (48)	
24	2	1.0 (35.9)	--	40 (44)	3.6 (4)	22 (24)	29 (32)	0.9 (1)	
25	2	3.8 (135.3)	--	185 (204)	7.2 (8)	103 (116)	137 (151)	0.9 (1)	
26	2	4.8 (168.0)	4.5 (160.0)	2607 (2874)	0.9 (1)	792 (873)	265 (292)	2.7 (3)	
27	2	2.7 (98.0)	2.2 (76.0)	559 (616)		206 (227)	67 (74)	0.9 (1)	
28	2	1.0 (37.0)	0.4 (14.7)	113 (125)		19 (21)	1.8 (2)	1.8 (2)	
29	2	33.4 (1180.0)	34.3 (1211.2)	447 (493)	0.9 (1)	1251 (1379)	1.8 (2)	1.8 (1)	
30	2	0.4 (15.6)	0.1 (4.5)	19 (21)		0.9 (1)			
31	-	--	--	41 (45)		254 (280)	10 (11)	5.4 (6)	7.2 (8)
32	2	43.1 (1520.5)	37.2 (1315.3)	630 (694)	1.8 (2)	588 (648)	27 (63)	34 (37)	
33	2	1.7 (59.0)	1.1 (40.5)	130 (143)		113 (125)	1.8 (2)	0.9 (1)	
34	6,7	3.4 (120.0)	2.6 (91.7)	4.5 (5)		9 (10)			
35	2,6,7	17.0 (600.0)	13.5 (478.3)	390 (430)	0.9 (1)	16 (18)	0.9 (1)	33 (36)	
36	2	0.4 (15.5)	0.3 (11.8)	21 (23)		2.7 (3)			
37	2	1.6 (55.0)	1.6 (57.3)	1524 (1680)		181 (200)	54 (60)	12 (13)	
38	2	45.9 (1620.0)	45.8 (1617.8)	980 (1080)	1.8 (2)	46 (51)	1.8 (2)	84 (93)	

TABLE 16 (Continued)

Number	Process Used[1]	Throughput hm^3/d (MMcfd)		Emissions in Metric Tons Per Year[1] (Short Tons)					
		1975[2]	1976[3]	NO_x	SO_x	HC	CO	Part.	H_2S
39	5	22.9 (807.1)	10.9 (386.0)	1672 (1843)		30 (33)	223 (246)		
40	2	0.008 .3	--	21 (23)		118 (130)	2.7 (3)	2.7 (3)	
41	2	0.6 (21.6)	0.5 (18.8)	223 (246)			105 (116)	0.9 (1)	
42	2	7.2 (113.4)	2.7 (96.4)	314 (346)	986 (1087)	641 (707)	8382 (9240)	10 (11)	
43	2,6	0.6 (21.5)	5.2 (185.0)	107 (118)		10 (11)		1.8 (2)	
44	2	0.7 (25.8)	0.6 (22.1)	219 (241)	544 (600)	242 (267)	4628 (5101)	5.4 (6)	
45	2,6	5.9 (209.0)	5.2 (185.0)	1491 (1644)		621 (685)	177 (195)	2.7 (3)	
46	6,7	0.6 (20.0)	--	14 (15)			10 (11)		
47	2	24.1 (850.0)	--	1042 (1149)		494 (54)	2390 (2635)	228 (251)	0.9 (1)
48	6,7	25.5 (900.0)	--	783 (863)		10 (11)	44 (49)		
49	2	22.2 (785.0)	--	1556 (1715)		194 (214)	315 (347)	47 (52)	3.6 (4)
50	1	0.04 (1.3)	0.2 (7.0)	2.7 (3)					
51	Sweetening				61 (67)				
52	Sweetening			9 (10)	4.5 (5)				
				24159 (26631)	1624 (1790)	7527 (8297)	17379 (19157)	625 (689)	14 (15)

NOTES:

[1]
1 - Absorption
2 - Refrigerated Absorption
3 - Refrigeration
4 - Compression
5 - Adsorption
6 - Cryogenic
7 - Expander

[2] Number obtained from 1975 Emission Inventory Questionnaire

[3] Number Obtained from Reference 5. Data is for 1976.

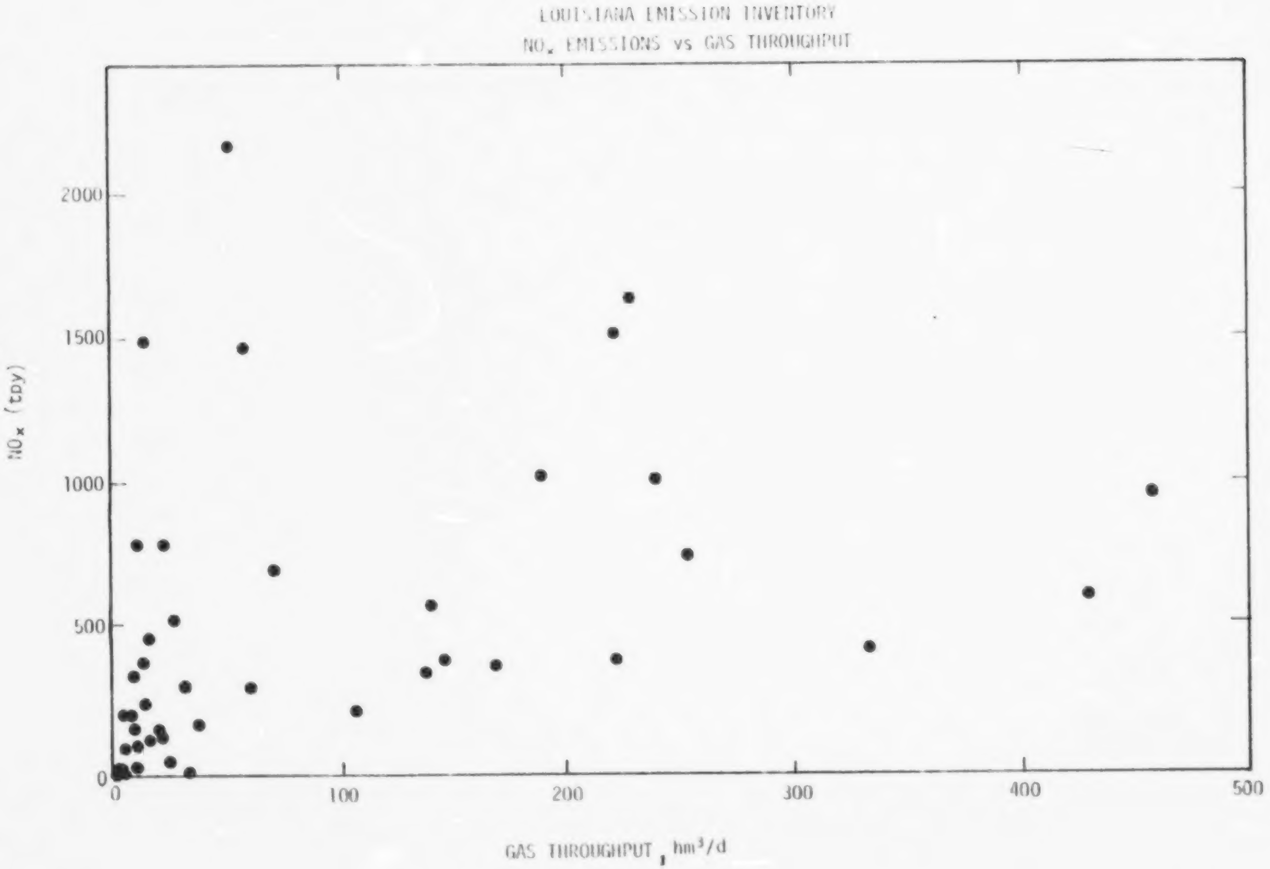


Figure 24: Louisiana emission inventory, NO$_x$ emissions (1973) vs. gas throughput for the natural gas processing industry.

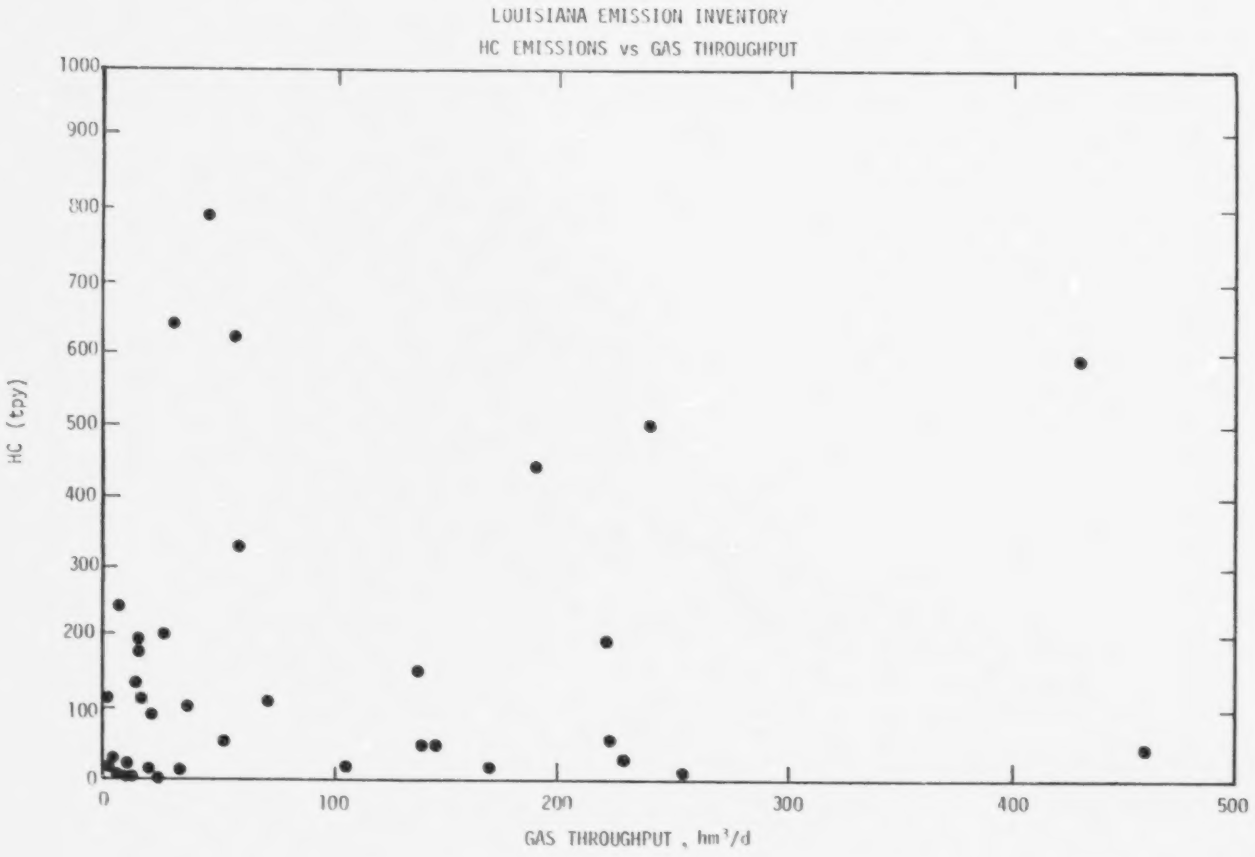


Figure 25: Louisiana emission inventory, HC emissions (1973) vs. gas throughput for the natural gas processing industry.

TABLE 17

FLARE EMISSIONS FOR NATURAL GAS PROCESSING INDUSTRY
LOUISIANA EMISSION INVENTORY, 1973

Plant Number	Charging Rate to Flare hm^3/year (MMcf/yr)	Emissions in Metric Tons/Year (Short Tons Per Year)					Emission Rate in Metric Tons/hm^3 (Short Tons Per MMcf)				
		NO_x	SO_x	HC	CO	Part.	NO_x	SO_x	HC	CO	Part.
1	0.11 (3.9)	.41 (.45)	.0005 (.0006)	.005 (.006)	.030 (.033)	.026 (.029)	3.68 (.115)	.0048 (.00015)	.0481 (.0015)	.2723 (.0085)	.2371 (.0074)
2	0.75 (26.6)	2.81 (3.10)	.0036 (.0040)	.036 (.040)	.209 (.230)	.181 (.200)	3.75 (.117)	.0048 (.00015)	.0481 (.0015)	.2750 (.0086)	.2403 (.0074)
3	0.07 (2.6)	.27 (.30)	.0004 (.0004)	.004 (.004)	.020 (.022)	.018 (.020)	3.68 (.115)	.0048 (.00015)	.0481 (.0015)	.2723 (.0085)	.2467 (.0077)
4	0.42 (14.9)	1.54 (1.70)	.0021 (.0023)	.020 (.022)	.118 (.130)	.100 (.110)	3.65 (.114)	.0048 (.00015)	.0481 (.0015)	.2787 (.0087)	.2371 (.0074)
5	0.02 (8.1)	.84 (.93)	.0011 (.0012)	.011 (.012)	.063 (.069)	.055 (.061)	3.68 (.115)	.0048 (.00015)	.0481 (.0015)	.2723 (.0085)	.2403 (.0075)
6	0.22 (7.7)	.80 (.88)	.0010 (.0011)	.010 (.011)	.060 (.066)	.051 (.057)	3.65 (.114)	.0045 (.00014)	.0449 (.0014)	.2755 (.0086)	.2371 (.0074)
10	0.08 (2.7)	.15 (.16)	--	.004 (.004)	.021 (.023)	.006 (.007)	1.89 (.059)	--	.0481 (.0015)	.2723 (.0085)	.0833 (.0026)
11	1.08 (38.1)	4.56 (5.03)	--	--	--	.830 (.915)	4.23 (.132)	--	--	--	.7689 (.0240)
12	0.88 (31.1)	3.73 (4.11)	--	--	--	.678 (.747)	4.23 (.132)	--	--	--	.7689 (.0240)
52	10.33 (365.0)	--	60.8 (67)	--	--	--	--	5.89 (.184)	--	--	--

TABLE 18

STORAGE TANK EMISSIONS FOR NATURAL GAS PROCESSING INDUSTRY
LOUISIANA EMISSION INVENTORY, 1973

Plant Number	Material Stored	Breathing Losses (MGal/Yr)	Working Losses (MGal/Yr)	Emissions in Metric Tons/Year (Short Tons Per Year)					Emission Rate (Tons Per MGal)				
				NO_x	SO_x	HC	CO	Part.	NO_x	SO_x	HC	CO	Part.
1	Methanol	6.3	4.6	--	--	.15 (17)	--	--	--	--	.0156	--	--
2	Methanol	8.4	40.8	--	--	1.63 (1.80)	--	--	--	--	.0366	--	--
2	Distilate and absorption oil	50.4	1944.4	--	--	0.09 (.10)	--	--	--	--	.0001	--	--
2	Slop tank	16.8	500.0	--	--	50.89 (56.10)	--	--	--	--	.1086	--	--
3	Methanol	3.8	2.6	--	--	.83 (.92)	--	--	--	--	.1433	--	--
3	Methanol	4.2	2.6	--	--	.87 (.96)	--	--	--	--	.1333	--	--
4	Absorption oil	16.8	173.7	--	--	.42 (.46)	--	--	--	--	.0024	--	--
5	Methanol	6.3	3.4	--	--	1.45 (1.60)	--	--	--	--	.1649	--	--
6	Absorption oil	10.0	78.0	--	--	.18 (.20)	--	--	--	--	.0023	--	--
6	Distillate	168.0	1499.0	--	--	.64 (.70)	--	--	--	--	.0004	--	--
8	Diesel oil	59.8	1.5	--	--	.07 (.08)	--	--	--	--	.0013	--	--
8	Distillate	202.0	21.7	--	--	.27 (.30)	--	--	--	--	.0013	--	--
8	Condensate	315.7	41.1	--	--	.48 (.44)	--	--	--	--	.0013	--	--
8	Condensate	271.5	35.2	--	--	.41 (.37)	--	--	--	--	.0013	--	--
9	Condensate	205.0	23.9	--	--	.31 (.28)	--	--	--	--	.0013	--	--
13	Absorption oil	.17	--	--	--	.49 (.54)	--	--	--	--	3.176	--	--
13	Sponge oil	.21	--	--	--	.64 (.70)	--	--	--	--	3.333	--	--
13	Scrubber oil	.60	.40	--	--	2.99 (3.30)	--	--	--	--	3.300	--	--
14	Condensate	.18	.17	--	--	.82 (.90)	--	--	--	--	2.571	--	--
14	Absorption oil	.09	.01	--	--	.27 (.30)	--	--	--	--	2.911	--	--

TABLE 19

ENGINE EMISSIONS FOR NATURAL GAS PROCESSING INDUSTRY
LOUISIANA EMISSION INVENTORY, 1973

Plant Number	Type of Engine	Charging Rate (MMcf/Yr)	Emissions in Metric Tons Per Year (Short Tons Per Year)					Emission Rate in Metric Tons Per hm^3 (Short Tons per MMcf)				
			NO_x	SO_x	HC	CO	Part.	NO_x	SO_x	HC	CO	Part.
1	Decompressor	30.1	43.7 (48.2)	.0041 (.0045)	.016 (.018)	--	--	51.29 (1.601)	.0048 (.00015)	.0192 (.0006)	--	--
1	Refrigeration Compressor	88.7	596.0 (657.0)	.0118 (.0130)	.048 (.053)	--	--	237.29 (7.407)	.0048 (.00015)	.0192 (.0006)	--	--
1	Generator	58.2	158.9 (175.2)	.0080 (.0088)	.032 (.035)	--	--	96.43 (3.010)	.0048 (.00015)	.0192 (.0006)	--	--
2	Refrigeration Compressor and Decompressor	157.8	181.4 (700.0)	.0218 (.0240)	.085 (.094)	--	--	142.11 (4.436)	.0048 (.00015)	.0192 (.0006)	--	--
2	Generator	53.3	43.7 (48.2)	.0073 (.0080)	.029 (.032)	--	--	28.96 (.904)	.0048 (.00015)	.0192 (.0006)	--	--
3	Decompressor	49.8	99.3 (109.5)	.0068 (.0075)	.027 (.030)	--	--	70.45 (2.199)	.0048 (.00015)	.0192 (.0006)	--	--
4	Decompressor	50.5	39.7 (43.8)	.0069 (.0076)	.027 (.030)	--	--	27.78 (.867)	.0048 (.00015)	.0192 (.0006)	--	--
4	Refrigeration Compressor	90.0	158.9 (175.2)	.0127 (.0140)	.049 (.054)	--	--	62.37 (1.947)	.0051 (.00016)	.0192 (.0006)	--	--
4	Generator	41.0	31.8 (35.0)	.0006 (.0062)	.023 (.025)	--	--	27.36 (.854)	.0048 (.00015)	.0192 (.0006)	--	--
5	Decompressor	35.0	43.7 (48.2)	.0048 (.0053)	.019 (.021)	--	--	44.11 (1.377)	.0048 (.00015)	.0192 (.0006)	--	--
5	Refrigeration Compressor	102.5	596.0 (657.0)	.0136 (.0150)	.056 (.062)	--	--	205.35 (6.410)	.0048 (.00015)	.0192 (.0006)	--	--
5	Compressor	19.3	0.4 (.4)	.0026 (.0029)	.011 (.012)	--	--	0.74 (0.23)	.0048 (.00015)	.0192 (.0006)	--	--
5	Generator	60.2	158.9 (175.2)	.0083 (.0091)	.083 (.036)	--	--	93.23 (2.910)	.0048 (.00015)	.0192 (.0006)	--	--
6	Decompressor	25.7	19.9 (21.9)	.0035 (.0039)	.014 (.015)	--	--	27.29 (.852)	.0048 (.00015)	.0192 (.0006)	--	--
6	Refrigeration Compressor	70.3	99.3 (109.5)	.0100 (.0110)	.038 (.042)	--	--	49.91 (1.558)	.0051 (.00016)	.0192 (.0006)	--	--
6	Generator	41.5	31.8 (35.0)	.0087 (.0063)	.023 (.025)	--	--	27.01 (.843)	.0048 (.00015)	.0192 (.0006)	--	--
6	Water Well Pump	3.1	3.2 (3.5)	.0005 (.0005)	.002 (.002)	--	--	36.17 (1.129)	.0048 (.00015)	.0192 (.0006)	--	--
8	Lean Oil Pump	27.7	8.0 (8.8)	.0073 (.0080)	15.096 (16.641)	--	--	10.12 (.316)	.0093 (.00029)	19.22 (.6000)	--	--
9	Compressor	2.4	0.2 (2)	.0007 (.0008)	1.313 (1.447)	--	--	2.72 (.985)	.0106 (.00033)	19.22 (.6000)	--	--
9	Refrigeration Compressor	3.6	0.4 (4)	.0009 (.0010)	1.970 (2.171)	--	--	3.20 (.100)	.0090 (.00028)	19.23 (.6001)	--	--

TABLE 19 (Continued)

Plant Number	Type of Engine	Charging Rate (MMcf/Yr)	Emissions in Metric Tons Per Year (Short Tons Per Year)					Emission Rate in Metric Tons Per hm^3 (Short Tons per MMcf)				
			NO$_x$	SO$_x$	HC	CO	Part.	NO$_x$	SO$_x$	HC	CO	Part.
10	Gas	22.0	20.0 (22.0)	--	11.793 (13.000)	--	--	32.04 (1.000)	--	18.93 (.5909)	--	--
10	Gas	55.5	59.9 (66.0)	--	29.937 (33.000)	--	--	38.09 (1.189)	--	19.05 (.5946)	--	--
10	Gas	18.0	10.0 (11.0)	--	9.979 (11.000)	--	--	19.57 (.611)	--	19.58 (.0111)	--	--
11	Fuel Gas Recompressor	28.7	56.1 (61.8)	--	--	--	--	68.97 (2.153)	--	--	--	--
12	Recycle Compressor	61.2	118.4 (131.6)	--	--	--	--	68.88 (2.150)	--	--	--	--
12	Compressor	80.7	157.3 (173.4)	--	--	--	--	68.85 (2.149)	--	--	--	--
12	Turbine	82.9	8.7 (9.6)	--	--	--	--	3.72 (.116)	--	--	--	--
14	Decompressor	26.6	19.9 (21.9)	.0073 (.0080)	.018 (.020)	5.90 (6.50)	0.73 (0.80)	26.37	.0096 (.00030)	.0256 (.0008)	--	--
14	Compressor	113.9	21.3 (23.5)	.2722 (.3000)	2.177 (2.400)	--	--	6.60 (.206)	.0843 (.00263)	.6760 (.0211)	1.83 (.057)	.2243 (.007)
14	Generator	39.1	25.9 (28.5)	.0091 (.0100)	.018 (.020)	--	--	23.35 (.729)	.0083 (.00026)	.0160 (.0005)	--	--
15	Internal Combustion	5.0	2.0 (2.2)	--	2.359 (2.600)	--	--	14.35 (.448)	--	16.73 (.5221)	--	--
15	Internal Combustion	7.4	3.0 (3.3)	--	3.502 (3.860)	--	--	14.38 (.449)	--	16.73 (.5223)	--	--
15	Internal Combustion	8.3	3.4 (3.7)	--	3.946 (4.350)	--	--	14.38 (.449)	--	16.79 (.5241)	--	--
15	Internal Combustion	.9	.4 (.4)	--	.408 (.450)	--	--	14.42 (.450)	--	16.63 (.5190)	--	--
15	Internal Combustion	3.2	1.3 (1.4)	--	1.515 (1.670)	--	--	14.42 (.450)	--	16.72 (.5219)	--	--
15	Internal Combustion	1.9	.7 (.8)	--	.889 (.980)	--	--	14.42 (.450)	--	16.79 (.5241)	--	--
16	Compressor	41.0	667.5 (735.8)	.5715 (.6300)	.953 (1.050)	16.21 (17.87)	9.53 (10.51)	574.96 (17.497)	.4924 (.01537)	0.8201 (.0256)	13.97 (.436)	8.20 (.256)

TABLE 20

HEATER EMISSIONS FOR NATURAL GAS PROCESSING INDUSTRY
LOUISIANA EMISSION INVENTORY, 1973

Plant Number	Type of Heater	Charging Rate (MMcf/Yr)	Emissions in Metric Tons Per Year (Short Tons Per Year)					Emission Rate in Metric Tons Per hm^3 (Short Tons per MMcf)				
			NO_x	SO_x	HC	CO	Part.	NO_x	SO_x	HC	CO	Part.
1	Fired Heater	153.9	16.5 (17.80	.0218 (.0240)	.218 (.240)	1.179 (1.300)	1.052 (1.160)	3.72 (.116)	.0048 (.00015)	.0481 (.0015)	.2691 (.0084)	.2403 (.0075)
1	Glycol Reboiler	7.5	.78 (.86)	.0010 (.0011)	.010 (.011)	.058 (.064)	.051 (.056)	3.68 (.115)	.0048 (.00015)	.0481 (.0015)	.2723 (.0085)	.2403 (.0075)
1	Salt Reclaimer Boiler	1.1	.12 (.13)	.0002 (.0002)	.002 (.002)	.009 (.010)	.008 (.009)	3.78 (.118)	.0048 (.00015)	.0481 (.0015)	.2819 (.0088)	.2499 (.0078)
2	Fired Heater	294.9	30.84 (34.00)	.0399 (.0440)	.399 (.440)	2.358 (2.600)	1.996 (2.200)	3.68 (.115)	.0048 (.00015)	.0481 (.0015)	.2819 (.0088)	.2403 (.0075)
2	Glycol Reboiler	29.8	3.08 (3.40)	.0041 (.0045)	.041 (.045)	.227 (.250)	.200 (.220)	3.65 (.114)	.0048 (.00015)	.0481 (.0015)	.2691 (.0084)	.2371 (.0074)
3	Glycol Reboiler	7.2	.74 (.82)	.0010 (.0011)	.010 (.011)	.050 (.061)	.049 (.054)	3.65 (.114)	.0048 (.00015)	.0481 (.0015)	.2723 (.0085)	.2499 (.0075)
4	Fired Heater	180.0	18.78 (20.70)	.0245 (.0270)	.245 (.270)	1.361 (1.500)	1.270 (1.400)	3.68 (.115)	.0048 (.00015)	.0481 (.0015)	.2659 (.0083)	.2499 (.0078)
4	Glycol Reboiler	4.4	.46 (.51)	.0006 (.0007)	.006 (.007)	.034 (.037)	.030 (.033)	3.72 (.116)	.0048 (.00015)	.0481 (.0015)	.6691 (.0084)	.2403 (.0075)
5	Fired Heater	140.9	14.70 (16.20)	.0200 (.0220)	.200 (.220)	1.089 (.200)	.962 (1.060)	3.68 (.115)	.0051 (.00016)	.0513 (.0016)	.2723 (.0085)	.2403 (.0075)
5	Glycol Reboiler	6.9	.73 (.80)	.0010 (.0011)	.009 (.010)	.054 (.059)	.047 (.052)	3.72 (.116)	.0051 (.00016)	.0449 (.0014)	.2765 (.0086)	.2403 (.0075)
5	Glycol Reboiler	0.4	.04	.0001 (.0001)	.001 (.001)	.003 (.003)	.003 (.003)	3.36 (.105)	.0045 (.00014)	.0449 (.0014)	.2499 (.0078)	.2243 (.0070)
6	Fired Heater	137.8	14.42 (15.90)	.0200 (.0220)	.200 (.220)	1.070 (1.180)	.934 (1.030)	3.68 (.115)	.0051 (.00016)	.0513 (.0016)	.2755 (.0086)	.2403 (.0075)
6	Glycol Reboiler	4.0	.41 (.45)	.0005 (.0006)	.005 (.006)	.031 (.034)	.027 (.030)	3.65 (.114)	.0048 (.00015)	.0481 (.0015)	.2755 (.0086)	.2435 (.0076)
7	Regenerator Gas Heater	64.6	3.51 (3.87)	.0181 (.0200)	.088 (.097)	.498 (.549)	.293 (.323)	1.92 (.060)	.0099 (.00031)	.0481 (.0015)	.2723 (.0085)	.1602 (.0050)
8	Boiler	39.5	2.15 (2.37)	.0109 (.0120)	.054 (.060)	.305 (.336)	.180 (.198)	1.92 (.060)	.0096 (.00030)	.0481 (.0015)	.2723 (.0085)	.1602 (.0050)
8	Boiler	195.9	10.66 (11.75)	.0535 (.0590)	.261 (.294)	1.511 (1.665)	.888 (.979)	1.92 (.060)	.0096 (.00030)	.0481 (.0015)	.2723 (.0085)	.1602 (.0050)
8	Rich Oil Heater	57.6	3.13 (3.45)	.0163 (.0180)	.078 (.086)	.444 (.489)	.261 (.288)	1.92 (.060)	.0096 (.00030)	.0481 (.0015)	.2691 (.0084)	.1602 (.0050)
8	Condensate Heater	5.2	.28 (.31)	.0018 (.0020)	.007 (.008)	.004 (.004)	.024 (.026)	1.92 (.060)	.0125 (.00039)	.0481 (.0015)	.0481 (.0015)	.1602 (.0050)
9	Glycol Conditioner	2.6	.15 (.16)	.0007 (.0008)	.004 (.004)	.020 (.022)	.012 (.013)	1.92 (.060)	.0099 (.00011)	.0481 (.0015)	.2691 (.0084)	.1602 (.0050)
9	Stabalizer Reboiler	5.2	.28 (.31)	.0018 (.0020)	.007 (.008)	.041 (.045)	.024 (.026)	1.92 (.060)	.0122 (.00038)	.0481 (.0015)	.2755 (.0086)	.1602 (.0050)

TABLE 20 (continued)

Plant Number	Type of	Charging Rate (MMcf/Yr)	Emissions in Metric Tons Per Year (Short Tons Per Year)					Emission Rate in Metric Tons Per hm³ (Short Tons per MMcf)				
			NO_x	SO_x	HC	CO	Part.	NO_x	SO_x	HC	CO	Part.
10	Process Heater	184.0	9.98 (11.00)	--	.236 (.260)	1.542 (1.700)	.363 (.400)	1.92 (.060)	--	.0449 (.0014)	.2947 (.0092)	.0705 (.0022)
10-	Oil Reclaimer	2.0	.11 (.12)	--	.003 (.003)	.015 (.017)	.005 (.005)	1.92 (.060)	--	.0481 (.0015)	.2723 (.0085)	.0801 (.0025)
11	Process Boiler	792.2	55.69 (61.39)	.2159 (.2380)	14.334 (15.800)	.143 (.158)	6.831 (7.530)	2.50 (.078)	.0096 (.00030)	.6375 (.0199)	.0064 (.0002)	.3043 (.0095)
11	Waste Heat Boiler	1997.0	173.09 (190.09)	.0644 (.0710)	4.282 (4.720)	.043 (.047)	2.032 (2.240)	3.08 (.096)	.0013 (.00004)	.0769 (.0024)	(.0000)	.0152 (.0011)
11	Regenerator Gas Heater	45.3	2.47 (2.72)	.0123 (.0136)	.822 (.906)	.008 (.009)	(.430)	1.92 (.060)	.0096 (.00030)	.6407 (.0200)	.0064 (.0002)	.3043 (.0095)
12	Boiler	219.0	12.79 (14.10)	.0608 (.0670)	4.028 (4.440)	.041 (.045)	(2.000)	2.05 (.064)	.0099 (.00031)	.6503 (.0203)	.0064 (.0002)	.2915 (.0091)
12	Rich Oil Heater	485.0	31.66 (34.90)	.1324 (.1460)	8.809 (9.710)	.088 (.097)	(4.370)	2.31 (.072)	.0096 (.00030)	.6407 (.0200)	.0064 (.0002)	.2883 (.0090)
12	Boiler	319.0	19.23 (21.20)	.0871 (.0960)	5.788 (6.380)	.058 (.064)	(2.870)	2.15 (.067)	.0096 (.00030)	.6407 (.0200)	.0064 (.0002)	.2883 (.0090)
12	Regenerator Heater	277.0	11.33 (18.00)	.0753 (.0830)	5.026 (5.540)	.051 (.056)	(2.490)	2.08 (.065)	.0096 (.00030)	.6407 (.0200)	.0064 (.0002)	.2883 (.0090)
12	Oil Heater	145.0	8.01 (8.83)	.0399 (.0440)	2.631 (2.900)	.026 (.029)	(1.300)	1.95 (.061)	.0096 (.00030)	.6407 (.0200)	.0064 (.0002)	.2883 (.0090)
12	Still Reboiler Heater	360.0	26.04 (28.70)	.0526 (.0580)	3.520 --	.035 (.039)	(1.750)	2.56 (.080)	.0051 (.00016)	.3524 (.0110	.0032 (.0001)	.1570 (.0049)
13	Steam Generator	668.0	(25.80)	(.2000)	(1.000)	(5.670)	(1.700)	1.25 (.039)	.0096 (.00030)	.0481 (.0015)	.2723 (.0085)	.0801 (.0025)
13	Steam Generator	780.0	(30.40)	(.2300)	(1.200)	(6.600)	(1.900)	1.25 (.039)	.0096 (.00030)	.0481 (.0015)	.2723 (.0085)	.0769 (.0024)
13	Boiler Feedwater Heater	46.8	(9.70)	(.1200)	(.980)	(2.700)	(.330)	6.63 (.207)	.0833 (.00260)	.6696 (.0209)	1.8485 (.0577)	.2275 (.0071)
13	Waste Heat Reclaimer Heater	489.0	(101.00)	(1.3000)	(10.300)	(28.100)	(3.400)	6.63 (.207)	.0815 (.00270)	.6760 (.0211)	1.8421 (.0575)	.2243 (.0070)
14	Fired Heater	144.0	(8.60)	(.0400)	(2.200)	--	(.360)	1.92 (.050)	.0327 (.00102)	1.8036 (.0563)	--	.2947 (.0092)
14	Fired Heater	38.7	(4.37)	--	(.502)	--	(.385)	3.62 (.113)	--	.4165 (.0130)	--	.3204 (.0100)
16	Heater	41.0	(40.30)	(.1051)	(.526)	(2.978)	(2.628)	31.5 (.983)	.0820 (.00256)	.5702 (.0178)	2.3258 (.0726)	2.0535 (.0641)
52	Gas Incinerator	95.0	(5.69)	(2.2600)	--	--	(.710)	1.92 (.060)	.7625 (.02380)	--	--	.2403 (.0075)
52	Dehydrator Process Heater	13.1	(.79)	(.3130)			(.099)	1.92 (.060)	.7625 (.02380)	--	--	.2403 (.00750
52	Gathering Line Heater	8.8	(.53)	(.2080)	--	--	(.066)	1.92 (.060)	.7625 (.02360)	--	--	.2403 (.0075

TABLE 21

EMISSION FACTORS FOR NATURAL-GAS COMBUSTION(20)

Pollutant	Industrial Process Boiler kg/hm^3	 (lb/mcf)
Particulates	80-240	(5-15)
Sulfur Oxides	9.6	(0.6)
Carbon Monoxide	272	(17)
Hydrocarbons	48	(3)
Nitrogen Oxides	1922-3684	(120-230)

TABLE 22

EMISSION FACTORS FOR HEAVY-DUTY, GENERAL-UTILITY, STATIONARY ENGINES USING GASEOUS FUELS(20)

Pollutant	kg/hm^3	(lb/mcf)
Sulfur Oxides	9.6	(0.6)
Hydrocarbons	19.2	(1.2)

The emissions of sulfur and nitrogen oxides and hydrocarbons in Louisiana as reported in the 1975 emission inventory are shown in Table 23. In contrast to the case in Texas, the natural gas processing industry is the sixth highest source of SO_x. The industry is the major source of NO_x in the state as in Texas. Also, as in Texas, natural gas processing is the third highest source of hydrocarbons exceeded by the same two industries, chemical manufacturing and the petroleum industry.

COMPLIANCE STATUS OF NATURAL GAS PLANTS

The report entitled "Compliance Status of Major Air Pollution Facilities" (EPA-340/1-77-011) was examined to determine whether any facility having one of the listed SIC codes was not in compliance. The facilities are listed in order by EPA region, state, and standard industrial classification (SIC) code. Six different SIC codes are pertinent to natural gas processing. These six are:

1311 - Crude petroleum and natural gas production including flares, dehydrators, separators, gas sweetening plants, and gas processing plants

1321 - Natural gas liquids

2819 - Industrial inorganic chemicals, not classified elsewhere, including sulfur recovery plants

4922 - Natural gas transmission

4923 - Natural gas transmission and distribution

4924 - Natural gas distribution.

Of all the plants in this publication, only six were found that were not in compliance and only one appears to be in operation at this time.

PROCESS SOURCES OF AIR POLLUTION

There are several sources of air pollution associated with natural gas processing. Some of these sources are unique to the industry while most are common to many types of industrial activity. Natural gas processing operations that are likely to be sources of air pollution include:

- wellhead testing and completion
- separation and dehydration
- acid gas removal
- sulfur recovery

TABLE 23

POINT SOURCE EMISSIONS FROM INDUSTRIAL PROCESSES
LOUISIANA EMISSION INVENTORY - 1975
POLLUTANT IN METRIC (SHORT) TONS PER YEAR

Industry	Sulfur Oxides	Nitrogen Oxides	Hydrocarbons
Natural Gas Processing	(3,580) 3,247	(53,262) 43,310	(16,594) 15,051
Petroleum Industry	(75,209) 68,217	(48,729) 43,790	(212,500) 192,744
Chemical Manufacturing	(113,253) 102,724	(17,073) 15,486	(585,926) 531,452
Primary Metal	(4,056) 3,679	(1,259) 1,142	(6,000) 5,442
Secondary Metals	(1,373) 1,245	(2,622) 2,378	(28) 25
Mineral Products	(9,870) 8,952	(6,658) 6,039	(29) 26
Wood Products	(5,932) 5,380	(1,237) 1,122	(144) 131
Food/Agriculture	(63) 57	(50) 45	(17) 15

- tail gas cleanup
- heavy hydrocarbon stripping.

General plant equipment likely to create air emissions are:

- gas engines
- flares
- storage tanks
- reciprocating pumps, compressors and valves

Possible emissions from well testing and completion are hydrogen sulfide, mercaptans, carbon disulfide and carbonyl sulfide (if the well contains sour gas), in addition to light hydrocarbon vapors which can create a safety hazard if not flared. These low temperature flares create many incomplete combustion products and SO_2 if the well is producing sour gas.

There are no emissions associated directly with field separation and dehydration since these operations are carried out in a closed system. However, reciprocating engines powered by natural gas, gasoline, or diesel fuel are used to provide power for the operations and create sulfur dioxide, hydrocarbons and NO_x. Lease tanks are another source of hydrocarbon emissions if they are vented to the atmosphere. For remote locations these off gases are usually flared. In some locations they are recycled or sold.

Gas sweetening produces waste acid gases which are usually flared or incinerated or sent to a sulfur recovery operation. The combustion of waste acid gases in flares is usually enhanced by adding natural gas to increase combustion temperatures. These ambient condition flares are usually 98% efficient and sulfur dioxide is the only major pollutant emitted. Modern smokeless flares with fuel and stream injection are more common today and are more efficient than the ambient condition type. A tail gas incinerator is a more elaborate and more efficient type of flare in which raw gas and oxygen are fed to the combustion chamber and H_2S is virtually completely converted to SO_2.

For sulfur recovery operations, SO_2 is usually converted to H_2S via catalytic hydrogenation or hydrolysis at 590-640°K (600-700°F). The products are then cooled to remove water vapor. Sodium carbonate solution is then added to yield sodium hydrosulfide. Sodium vanadate is then used to oxidize this to elemental sulfur. The finely divided sulfur froth is skimmed and dried by centrifugation for sale. Overall recovery approaches 100%.

Heavy hydrocarbon stripping operations are usually powered by internal combustion engines yielding combustion related emissions, NO_x, SO_x, and hydrocarbons. Storage tanks are a major source of hydrocarbon emissions to the atmosphere via working (filling) and breathing. Most modern facilities have emissions controls to reduce these losses. Such controls include vapor recovery, incineration flaring, as well as floating roof and variable vapor space storage tank designs. The floating roof design usually yields a 90% emissions reduction. Variable vapor space tanks are similarly effective. This type of tank has a movable lifter roof which rises and falls with changes in vapor volume. Other types have a flexible diaphragm that compensates for changes in vapor volume. Vapor recovery systems maintain a slight positive pressure of natural gas on a manifold connected to several tanks. Any vapor generated by the tanks is compressed and piped to the installation's fuel system.

Glycol losses are associated with refrigeration absorption processes. As mentioned earlier, some losses of this material occur when water vapor is vented in the dehydration process.

SECTION 7

WATER POLLUTION ASPECTS OF THE DOMESTIC NATURAL GAS PROCESSING INDUSTRY

The major sources of water pollution from natural gas processing operations are produced water, extracted with the hydrocarbons from the well, and cooling water used to extract heat from process operations and equipment. The produced water is very often a highly concentrated brine. Cooling water usually contains corrosion inhibitors and antifoulants to protect process equipment. The major sources of wastewater are listed in Table 24.

Typical wastewater characteristics for different types of gas processing facilities are shown in Table 25. As the data show, there is substantial variation in values reported on the NPDES permits. There is no correlation between gas throughput and flow or pollutant loadings. Many of the plants have several different permits for surface water discharge, underground injection and underground disposal. Some wastes are disposed of by evaporation or are hauled off-site by licensed scavengers. The myriad permits and disposal options available to a specific plant have made it virtually impossible to generate a satisfactory relationship between plant type or size, and pollutant loadings. Our development of an industry-wide assessment of the industry's water pollution aspects has been frustrated by the multiplicity of inconsistencies in the data, conflicting reports and absence of information.

We can make several general observations regarding gas processing plant effluents, their characteristics and general means of disposal.

PRODUCED WATER

Produced water is usually re-injected into the gas producing strata to enhance well production. If re-injection does not improve gas recovery, the produced water is often injected into non-producing, porous rock structures. Because of the risk of contaminating freshwater aquifers, this disposal option is regulated by permit. Discharge of produced water into surface waters is non-existent. Such disposal of saline wastes would have substantial impact on freshwater streams. It is unclear if the re-injected wastes may also include blowdown, deionizer regenerants, and process and scrubber wastes.

COOLING WATER

Generally, cooling water comprises the largest portion of wastewater discharged from gas plants, typically from 70 to 100% of the total wastewater generated. Although some plants use once through cooling which avoids the

TABLE 24

SOURCES OF WASTEWATER - NATURAL GAS PROCESSING OPERATIONS

	Cooling Water	Separated Water	Produced Water (Condensate)	Process Water (Scrubber Water, etc.)	Process Leaks	Wash Water	Blowdown	Backwash	Deionizer Regenerant
Liquid Separation		X				X			
Acid Gas Removal	X		X		X	X			
Dehydration	X		X		X	X			
Sulfur Recovery	X			X	X	X			
Tail Gas Conditioning	X					X			
Heavy Hydrocarbon Stripping	X				X	X			
Power Plant	X					X	X	X	X

TABLE 25

NATURAL GAS PROCESSING PLANTS TYPICAL DISCHARGE CHARACTERISTICS (1)

	Absorption (14 Plants)	Refrigerated Absorption (23 Plants)	Other (8 Plants)	Combined (49 Plants)
Flow, $\frac{m^3 \text{ discharged}}{10^6 \ m^3 \text{ gas produced}}$	12-635[1] 81[2]	3-3,324 79	4-152 43	3-3,324 51
pH, Standard units	6.5-8.0 7.7	7.3-8.2 7.4	6.4-9.8 7.7	6.4-9.8 7.7
BODs, mg/ℓ	4.1-87 34	4.4-150 17	1.0-281 11	1.0-281 15
COD, mg/ℓ	29-190 79	40-95 75	2.3-640 130	2.3-640 98
Oil & Grease, mg/ℓ	0-10 3.3	2.0-15 10	0-75 1.5	0-75 3.0
Chromium, mg/ℓ	0-15 1.8	0.4-3.2 1.3	0-2.5 0.2	0-15 0.8
Zinc, mg/ℓ	0.2-3.1 1.6	0.2-0.9 0.4	0-0.9 0.2	0-3.1 0.3
TDS, mg/ℓ	2,300-9,700 3,400	3,900-8,000 4,600	1,000-28,000 3,900	1,000-28,000 4,000
Chloride, mg/ℓ	140-1,600 310	180-1,100 950	70-17,000 9,500	70-17,000 750
Sulfate, mg/ℓ	560-2,100 1,400	300-620 520	9.5-1,800 700	9.7-2,100 600

[1] EPA Region VI NPDES Permits

[2] Low-high Median

necessity of water treatment, most plants use varying degrees of recirculation. Recirculation, often to 4 cycles of concentration, requires some degree of pH and corrosion control to protect process equipment. Chromium, zinc and phosphate compounds are common ingredients in corrosion inhibitors. Antifoulants may contain chlorine compounds and possibly minute amounts of toxic materials to prevent biological growth. Cooling water blowdown thus contains measurable quantities of these compounds plus high dissolved solids and any materials that may leak into the cooling water from the process equipment. These leaks, which are minimized by good maintenance practices, often increase the oil, grease, and BOD_5 content of the cooling water blowdown.

OTHER SOURCES OF WATER POLLUTION

Boiler blowdown is usually the third most significant source of plant wastewater. These waters also contain treatment chemicals for corrosion and fouling control similar to cooling water blowdown. There are no other materials such as oil and grease, or BOD_5/COD usually associated with these wastes.

Spills, leaks and stormwater runoff comprise an additional and unpredictable fraction of plant wastewaters. They are an undetermined factor in the total picture.

Condensed stripping steam is also a possible source of wastewater within plants that use wet system oil separation. These waters are often very high in oil and grease, BOD_5, and COD.

WASTEWATER TREATMENT

The quality of wastewater discharge is controlled by:

- good plant operation and maintenance practice
- use of non-polluting water treatment chemicals
- end of pipe treatment.

Good plant operation, including timely cleanup of leaks and spills and segregation of runoff from plant wastewater systems, is routinely applied. Substitutes for chrome-zinc corrosion inhibitors are available but frequently offer less than desirable protection for process equipment.

End of pipe treatment includes oil-water separation, reduction-precipitation for heavy metals and biological oxidation and cooling lagoons and ditches.

The control parameters for plant wastewater discharges are: pH, temperature, BOD_5, COD, oil, and grease. For plants using recirculated cooling water, chromium and zinc limitations are also included.

The following concentrations represent the best practicable control technology currently available (BPCTCA):

	Monthly Average (mg/ℓ)	24-hr Average (mg/ℓ)
BOD_5	20	24
COD	200	350
Oil & Grease	10	12
Total Chromium	0.25	0.25
Zinc	1.0	1.0
pH	6.0 - 9.0	

It is also likely that local conditions could allow the injection of all plant wastewater, in addition to produced water, into underground strata. Land disposal by percolation is discouraged at this time. Solar evaporation ponds must be lined and are used to dispose of an undetermined quantity of wastes, primarily produced water, but may also include process water.

REFERENCES

1. U.S. Bureau of Mines, Minerals Yearbook - 1974.

2. American Gas Association, Gas Facts - 1976.

3. Oil & Gas Journal, Worldwide Directory of Refining and Gas Processing -1977-1978.

4. Oil & Gas Journal, Petroleum-2000, 1977.

5. Federal Energy Administration, National Energy Outlook, 1977.

6. American Petroleum Institute, Crude Petroleum, Products & NGL, 1973.

7. Chase Manhattan Bank, Energy Economics Division publication, 1977.

8. Federal Power Commission Bureau of Natural Gas; The Gas Supplies of Interstate Natural Gas Pipeline Companies, 1975; January 1977.

9. "Atmospheric Emissions Survey of the Sour Gas Processing Industry," Ecology Audits, Inc., EPA-450/3-75-076, October 1975.

10. "Screening Report - Crude Oil & Natural Gas Production Processes-Final Report," Processes Research Inc., EPA-R2-73-285, December 27, 1972.

11. "Process for Sour Natural Gas Treating," A.H. Younger, AICHE Symposium Series, No. 148, Vol 71.

12. "Field Surveillance and Enforcement Guide for Petroleum Refineries," A.V. Sims, EPA-450/3-74-042, July 1974.

13. "Characterization of Sulfur Recovery in Oil and Natural Gas Production," K.S. Murthy, EPA-450/3-75-081, August 1974.

14. "API Recommended Gas Plant Good Operating Practices for Protection of the Environment," APIRPSO, January 1975.

15. "Environmental Problem Definition for Petroleum Refineries, Synthetic Natural Gas Plants, and Liquified Natural Gas Plants," EPA-600/2-75-068, E.C. Cavanaugh, J.D. Colley, P.S. Dzierlenga, V.M. Felix, D.C. Jones, T.P. Nelson, November 1975.

16. "Natural Gas Processing at Low Temperatures," C.M. Jordan, Chemical Engineering Progress, Vol 68, No. 9, September 1972.

17. "U.S. Gas Processing Continues to Slide from 1972 Peak," E. Seaton, The Oil and Gas Journal, July 11, 1977.

18. "Gas Processing Looks to the Future," C.P. Mathias, B.L. Kline, J.E. Moody, The Oil and Gas Journal, 75th Anniversary Issue, August 1977.

19. 1977 Directory of Chemical Producers - U.S.A. Chemical Information Services, Stamford Research Institute.

20. "Compilation of Air Pollutant Emission Factors," EPA AP-42.

APPENDIX A

LIST OF NATURAL GAS PROCESSING PLANTS, CAPACITIES, PRODUCTS AS OF JANUARY 1, 1977(3)

Company, plant, location	MMcfd Gas capacity	MMcfd Gas through-put	Process method	Production—1,000 gal/day (Average based on the past 12 months) Ethane	Prop.	Isobut.	Normal or unsplit butane	LP-gas mix	Raw NGL mix	Debut. nat. gaso.	Othe
Marathon Oil Co.—*South Coles Levee plant and field, Kern County, 3-31s-25e	80.0	77.1	2	....	39.4	5.9	7.5	23.7	....	26.5	[11]33.
Petrolane Gasoline Co.—Harbor plant, Wilmington field, Los Angeles County	50.0	31.0	3	....	....	....	....	....	9.5	....	....
Signal Hill plant, Long Beach field, Los Angeles County	10.0	8.0	3	....	4.5	....	....	....	46.6	....	....
Reserve Oil Inc.*—Reserve Standard plant, North Tejon field, Kern County, 17-11n-19w	40.0	4.8	5	....	....	....	....	....	0.6	....	....
Shell Oil Co.—Molino plant and field, Santa Barbara County, 35-5n-31w	45.0	2.0	2	....	1.6	....	....	....	....	1.9	....
Ventura plant, Sespa-Ventura field, Ventura County, 28-3n-23w	120.0	14.0	1	....	16.6	....	....	....	....	27.5	....
Sun Production Co.—Newhall plant, RSF field, Los Angeles County, 27-4n-14w	70.0	29.4	2	....	19.4	....	....	....	12.3	....	....
Superior Oil Co.—Rio Bravo plant, various fields, Kern County, 34&35-28s-25e	38.0	20.0	1	....	6.0	1.2	2.1	....	....	3.2	....
Texaco Inc.‡—Honor Rancho plant, Los Angeles County, 36-5n-17w-SBBM	18.0	NR	1	....	20.0	....	16.0	....	16.0	....	....
Shields Canyon plant, Ventura County, 4-4n-19w-SBBM	10.0	NR	1	....	22.0	....	17.0	....	33.0	.	....
Union Oil Company of California—											
Bell plant, Santa Fe Springs field, Los Angeles County, 6-35-11w	9.0	1.8	NR	....	....	....	....	....	....	9.2	....
*Coalinga Nose plant and field, Fresno County, 7-20s-16e	46.0	58.2	1	....	17.0	14.0	10.6	....	....	19.7	....
Dominguez plant and field, Los Angeles County, 33-3s-9w	20.0	3.9	1	....	5.3	....	....	....	8.7	....	....
Santa Clara Valley plant, Torrey field, Ventura County, 4n-18w	20.0	20.0	3	....	....	....	....	13.1	8.8	....	....
Santa Maria plant, Santa Maria Valley field, Santa Barbara County, 24-10n-34w	35.0	17.0	1	....	23.8	....	16.2	....	....	17.4	....
Stearns plant, Brea-Olinda field, Orange County, 7-3s-9w	20.0	9.2	1	....	16.7	....	....	....	29.1	....	....
Total	**1,427.0**	**553.9**		....	**341.4**	**25.8**	**111.7**	**54.1**	**353.7**	**168.4**	**33.**

‡All figures are capacity

COLORADO

Company, plant, location	Gas capacity	Gas through-put	Process method	Ethane	Prop.	Isobut.	Normal or unsplit butane	LP-gas mix	Raw NGL mix	Debut. nat. gaso.	Othe
Amoco Production Co.—Peoria plant and field, Arapahoe County, 33-4s-60w	10.0	7.3	7	....	19.0	....	....	23.7	17.9	....	....
Spindle plant and field, Weld County, 34-2n-67w	30.0	30.0	7	....	....	....	....	....	174.2	....	....
Third Creek plant and field, Adams County, 7-2s-65w	10.0	4.0	3	....	....	....	....	9.7	....	....	....
Wattenberg plant and field, Adams County, 32-3s-65w	150.0	119.0	7	....	....	....	....	417.8	....	....	....
Chevron USA Inc.—Rangely Hagood plant and field, Rio Blanco County	10.0	5.0	3	....	....	....	....	....	30.3	....	....
Continental Oil Co.—Fruita plant, Western Slope Gas Co. field, Mesa County, 34-9s-10w	20.0	18.4	5	....	9.0	....	7.1	....	2.9	....	....
Crystal Oil Co.—Crystal Gas Resources plant, Roggen field, Weld County	21.0	14.0	2	....	....	....	....	44.0	....	....	....
Excelsior Oil Corp.—Yenter plant, various fields, Logan County, 1-11-53	10.0	3.1	2	....	6.1	....	....	....	6.7	....	....
Koch Oil Co.—Third Creek plant, various fields, Adams County, 18-2s-65w	25.0	17.7	2	17.3	34.7	....	5.2	....	....	13.0	....
Matrix Land Co.—Piceance Creek plant and field, Rio Blanco County, 15-25-96w	40.0	26.0	2	....	6.5	....	....	8.0	....	....	....
Northwest Pipeline Corp.—Ignacio plant, San Juan Basin field, La Platte County, sw½-36-34n-9w	300.0	194.2	1	....	45.4	....	57.7	....	....	48.1	....
Phillips Petroleum Co.—‡Weld plant, Tampa, field, Kiowa & Bent Counties,				....	....	....	....	....	60.0	....	....
Planet Engineers Inc.—McClave plant and field, Kiowa & Bent Counties, 32-48w-20s	7.0	5.0	2	....	4.5	....	....	....	3.3	....	....
Sun Production Co.—Denver Central plant, several fields, Arapaho County, 5-5s-62w	12.0	7.7	2	....	18.6	....	....	....	13.3	....	....
Dragon Trail plant and field, Rio Blanco County, 35-2s-102w	20.0	13.4	2	....	11.5	....	....	....	11.8	....	....
Texaco Inc.—‡Wilson Creek plant and field, Rio Blanco County, 27-3n-94w	10.5	NR	3	21.0	....	....	....	....	21.0	....	....
Union Oil Company of California—Adena plant and field, Morgan County, 12-1n-58w	28.0	4.1	2	....	8.7	....	2.4	....	7.0	....	....
Vallery Corp.—Vallery plant, Poe, Lamb, Canal, Vallery, Renegade fields, Morgan County, 15-3n-59w	3.0	2.0	3	....	3.0	....	....	....	....	....	....
Vessels Gas Processing Co.—Bennett plant *and field, Adams County, nw corner-ne4-28-2s-63w*	1.0	0.6	4	....	....	....	....	....	0.8	....	....
Brighton plant, Spindle field, Weld County, se4-28-1n-67w	15.0	8.0	3	....	5.8	....	10.8	....	....	....	

Company, plant, location	MMcfd			Production—1,000 gal/day (Average based on the past 12 months)							
	Gas capacity	Gas throughput	Process method	Ethane	Prop.	Isobut.	Normal or unsplit butane	LP-gas mix	Raw NGL mix	Debut. nat. gaso.	Other
Bugle plant and field, Adams County, sw corner-sw4-32-1s-66w	1.0	1.0	3	....	....	....	....	....	2.7	....	....
Irondale plant and field, Adams County, sw corner-se4-24-2s-62w	15.0	4.0	3	....	7.8	....	9.2	....	....	....	....
Irondale Cryogenics plant, Irondale field, Adams County, sw corner-se4-24-2s-62w	10.0	3.0	6	....	....	....	....	....	9.1	....	....
Space City plant and field, Weld County, ne4-31-1n-65w	4.0	2.0	3	....	....	....	....	....	3.6	....	....
Total	**767.5**	**509.9**		**34.1**	**180.6**	....	**82.4**	**503.2**	**318.1**	**91.4**	
FLORIDA											
Exxon Co. USA—Jay plant, Jay field, LEC unit, Santa Rosa County, 43-5n-30w	90.0	124.0	6&7	391.8	328.3	....	176.5	....	....	113.6	....
Florida Hydrocarbons Co.—Brooker plant, Bradford County	NR	506.0	NR	....	34.6	....	25.9	....	25.5	....	....
Total	**722.5**	**630.0**		**391.8**	**362.9**		**202.4**	....	**25.5**	**113.6**	....
ILLINOIS											
U.S. Industrial Chemicals Co. Division of National Distillers & Chemical Corp.—Tuscola plant, Hugoton via PEPL, Douglas County, Ficklyn Township	550.0	411.0	2	482.9	247.2	48.7	110.2	....	....	25.5	....
Total	**550.0**	**411.0**		**482.9**	**247.2**	**48.7**	**110.2**	....	....	**25.5**	....
KANSAS											
Alamo Chemical Co. (owned by Phillips Petroleum Co.)—†Greenwood plant, Greenwood-Sparks field, Morton County, se4-se4-7-33s-43w	84.0	NR	3	....	....	....	....	....	60.0	....	....
Amoco Production Co.—Kinsler plant and field, Grant County, 10-30s-37w	20.0	5.5	2	....	....	....	....	14.2	....	....	[11]0.6
Ulysses plant, Hugoton field, Grant County, 5-29s-38w	400.0	326.0	2	....	107.8	30.7	92.7	....	....	89.6	....
Anadarko Production Co.—Cimarron River plant and field, Seward County, 26-33s-32w	15.0	18.0	2	....	10.4	....	....	13.9	....	....	....
Interstate plant, Interstate-Baca field, Morton County, 29-34s-43w	16.0	4.0	2	....	6.5	....	....	6.2	....	....	....
Woods plant, Council Grove field, Seward County, 22-33s-34w	10.0	9.5	2	....	3.2	....	....	5.2	....	....	....
Central States Gas Co.—Rattle Snake Creek plant, Stafford County, nw 10 acres of ne4-28-25s-13w	12.0	7.0	2	....	....	....	....	....	4.5	....	....
Cities Service Co.—Cheney plant, various fields, Kingman County, 22-28s-5w	100.0	84.8	2	....	....	....	....	....	72.2	....	....
Hutchinson fractionation plant, various fields, Reno County, 22-235-6w	....	....	....	....	(762.0)	(97.6)	(310.8)	....	....	(343.6)	....
Jayhawk plant, Kansas-Hugoton field, Grant County, 2-29-35w	520.0	486.0	2&6	....	....	....	....	....	434.8	....	....
Midway plant, various fields, Kingman County, 33-275-5w	25.0	20.7	2	....	....	....	....	....	30.5	....	....
Spivey plant, Spivey-Grabs field, Harper County, 5-31s-8w	70.0	48.9	1	....	1.8	....	0.5	....	....	1.6	....
Sunflower plant, Kansas-Hugoton field, Scott County, 17-18-33w	250.0	157.8	3&6	....	....	....	....	....	84.8	....	....
Wichita plant, various fields, Sedgwick County, 17-28-1e	130.0	100.2	1	....	46.7	15.9	37.5	....	....	30.8	....
Wilburton plant, S. Taloga & Wilburton fields, Morton County, 33-34s-41w	5.5	3.2	3	....	....	....	....	....	11.6	....	....
Colorado Interstate Gas Co.—Lakin plant, Hugoton field, Kearney County, n 2 of ne4-29-24s-36w	215.0	137.0	1	....	....	....	....	....	21.5	....	....
Morton plant, Greenwood field, Morton County, ne4-18-33s-43w	112.0	46.0	5	....	....	....	....	....	....	....	§0.5
Kansas Refined Helium Co.—Otis plant, Reichel and other fields, Rush County, 26-17-16w	24.0	24.0	3	....	....	....	....	....	4.9	....	....
Mesa Petroleum Co.—Ulysses plant, Hugoton field, Grant County, 10-30s-37w	242.0	147.3	2	....	....	....	....	....	122.0	....	....
Mobil Oil Corp.—Hickok plant, Hugoton field, Grant County, 31-28s-35w	210.0	121.1	1	....	16.5	....	....	....	44.9	....	....
National Helium Corp.—National Helium plant, Seward County, 23-335-32w	1,000.0	610.0	3	....	163.0	....	34.0	....	119.0	....	....
Northern Gas Products—Northern Gas plant, Ellsworth County, 31-17s-9w	950.0	900.0	2	420.0	650.0	70.0	170.0	....	....	115.0	....
Northern Helex Co.—Northern Helex plant, Ellsworth County, 31-17s-9w	520.0	500.0	NR	....	....	....	....	....	....	....	(T)
Northern Natural Gas Co.—Holcomb plant, Hugoton field, Finney County, 3-24s-34w	200.0	192.0	3	....	....	....	....	....	....	21.1	....

Company, plant, location	MMcfd Gas capacity	 Gas throughput	Process method	Production—1,000 gal/day (Average based on the past 12 months) Ethane	 Prop.	 Isobut.	 Normal or unsplit butane	 LP-gas mix	 Raw NGL mix	 Debut. nat. gaso.	 Other
Sublette plant, Hugoton field, Seward County, 1-32s-33w	325.0	302.0	1							41.9	
Peoples Natural Gas—Burrton plant and field, Harvey County, nw4-23-23s-3w	3.0	1.2	2						0.4		
Johnson plant, Hugoton field, Stanton County, nw4-33-28s-40w	7.0	6.5	2						0.7		
Skelly Oil Co.—Medicine Lodge plant, various fields, 13-32s-12w	30.0	NR	1		6.0				7.0		
Minneola plant, various fields, Ford County, 13-298-25w	25.0	NR	2		6.0				6.0		
Total	**5,520.5**	**4,369.9**		**420.0**	**1,017.9**	**116.6**	**334.7**	**39.5**	**1,012.8**	**200.0**	**1.1**

*Cycling. †All figures capacity. ‡Fractionation. (Figures in parenthesis do not represent primary production, and are not added in state totals.) §Weathered natural gasoline. ¶Helium (crude) 1.6 Mcfd.

KENTUCKY

Company, plant, location	Gas capacity	Gas throughput	Process method	Ethane	Prop.	Isobut.	Normal or unsplit butane	LP-gas mix	Raw NGL mix	Debut. nat. gaso.	Other
Kentucky Hydrocarbon—Kentucky HC plant, Floyd County	50.0	42.8	3								*244.0
Tennessee Gas Pipeline Co.—Gabe plant, Transmission line field, Green County	845.0	627.0	3	107.0	34.0		22.0			30.0	
Total	**895.0**	**669.8**		**107.0**	**34.0**		**22.0**			**30.0**	**244.0**

LOUISIANA

Company, plant, location	Gas capacity	Gas throughput	Process method	Ethane	Prop.	Isobut.	Normal or unsplit butane	LP-gas mix	Raw NGL mix	Debut. nat. gaso.	Other
Amoco Production Co.—Big Lake plant and field, Cameron Parish, 2-12s-8e	17.5	5.0	5								
Lake Boeuf plant and field, Lafourche Parish, 61-15s-18e	120.0	31.0	2						54.5		
South Jennings plant and field, Jefferson Davis Parish, 5-10s-2w	55.0	28.0	2						26.9		
South Manchester plant, S, SW & W Manchester fields, Calcasieu Parish, 22-10s-7w	80.0	26.0	2						69.5		
South Pecan Lake plant, South Pecan Lake, Little Pecan Lake, Twin Island, East Cameron Block 33 fields, Cameron Parish, 2-12s-9w	120.0	66.0	2						54.5		
South Thornwell plant and field, Jefferson Parish, 3-11s-2w	95.0	44.0	2						47.5		
TSMA plant, Vermilion Block 14, Vermilion 60 & 39, North Freshwater Bayou, Redfish Point fields, Vermilion Parish, 11-14s-1e	340.0	190.0	2						168.6		
Anchor Gasoline Corp.—Krotz Springs plant, Happytown field, Pointe Coupee Parish, 40 & 41-6s-7e	50.0	NR	1					16.0	5.3		
Arkansas Louisiana Gas Co.—Bistineau plant, Ada-Bistineau fields, Webster Parish, se36-17n-10w, se31-17n-9w	60.0	27.0	1					5.4		8.5	
Calhoun plant and field, Ouachita Parish, se-34-18n-1e	60.0	7.1	5							0.2	
Gayles plant, Elm Grove field, Caddo Parish, 30-16n-12w	20.0	7.0	5							1.5	
Minden plant and field, Webster Parish, 18-19n-8w	0.5	0.4	3						0.5		
Sligo plant and field, Bossier Parish, se-7-18s-21w	75.0	7.1	1					2.0		3.0	*0.1
Atlantic Richfield Co.*—Bayou Sale plant and field, St. Mary Parish, 17-11s-9e	97.0	79.0	2		22.9		13.3			17.3	
Beacon Gasoline Co.—Webster Parish plant, various fields, Webster Parish	72.0	20.0	2		15.0	6.0	7.0			10.0	*
Chevron USA Inc.—Simon Pass plant and field, St. Martin Parish, 22-15s-13e	20.0	17.0	5						2.7		
West Cameron plant and field, Cameron Parish, 7-15s-15w	200.0	160.0	2						115.0		
Cities Service Co.—Crowley plant, Lawson field, Acadia Parish, 41 & 44-9s-1wie	45.0	23.0	7	4.5	4.3	2.2	1.5			3.6	
Lake Charles plant, various fields, Calcasieu Parish, 19-10s-9w			(†)	(24.4)	(49.0)		(6.5)			(24.7)	
St. Amelia plant and field, St. James Parish, 12-12s-16e	38.0	10.0	2		2.8		1.8			1.6	
laiborne Gasoline Co.—Claiborne plant, Lisbon, Mt. Olive, Bayou Middlefork fields, Claiborne and Union Parish, 20-21n-4w	NR	43.9	2		33.7	16.4	20.7		36.1		*52.8 *20.5 *0.3 *918.5
Continental Oil Co.—Acadia plant, Midland and other fields, Acadia Parish, 31-9s-1w	250.0	69.9	2&6	58.7	42.1		28.6				*101.8 *31.8 *0.9 *18.9
Gillis plant, Louisiana Gas System field, Calcasieu Parish, 14-9s-8w	260.0	258.9	2&5	115.8	89.8	30.3	26.8			35.2	

Company, plant, location	MMcfd Gas capacity	Gas throughput	Process method	Production—1,000 gal/day (Average based on the past 12 months) Ethane	Prop.	Isobut.	Normal or unsplit butane	LP-gas mix	Raw NGL mix	Debut. nat. gaso.	Other
Grand Chenier plant, Tennessee Gas Transmission Line, Cameron Parish, 2-39-40-15s-6w	950.0	671.5	2&6	(Liquids fractionated by others)				597.5	....	....	....
Crystal Oil Co.—Kings Bayou plant, Hog Bayou-Kings Bayou field, Cameron Parish	80.0	45.0	2	10.2	9.2	2.8	2.0	....	....	4.3	....
Exxon Co. USA—Avery Island plant and field, Iberia Parish, 53-13s-5e	11.0	13.0	2	....	....	....	....	....	8.4	....	....
College Point plant and field, St. James Parish	20.0	4.0	5	....	....	....	....	....	....	0.5	....
Garden City plant and field, St. Mary Parish, 45-46-15s-10e	960.0	380.0	2	159.3	133.4	40.7	31.6	....	....	70.9	....
Grand Isle plant and field, Jefferson Parish, 32-21s-25e	100.0	76.0	2	14.7	17.8	9.2	9.8	....	....	....	....
Lirette plant and field, Terrebonne Parish, 23-19s-19e	300.0	215.0	2	....	....	....	....	....	230.8	....	....
Opelousas plant, St. Landry Parish, 100-6s-4e	110.0	127.0	2	....	25.7	10.6	9.6	....	21.3	....	....
Thibodaux plant, Lafourche Parish, 35-36-15s-16e	15.0	9.0	2	....	3.7	....	....	....	5.8	....	....
Getty Oil Co.—Bastian Bay plant, West Bastian Bay field, Plaquemines Parish, 21s-28e-42	150.0	56.6	7	....	....	....	....	....	83.6	....	....
Cameron plant and field, Cameron Parish, 29-14s-9w	65.0	NR	2	....	....	....	....	....	8.0	....	[13]1.0
Hollywood plant and field, Terrebone Parish, 17s-17e-101	150.0	89.4	2	....	....	....	....	....	53.6	....	....
Venice plant and field, Plaquemines Parish, 21s-30e-25	65.0	41.7	2	....	....	....	....	....	47.2	....	....
Gulf Energy and Minerals Co.—Krotz Springs plant and field, St. Landry Parish, 22-6s-6&7e	100.0	46.0	2	....	47.9	....	31.2	....	....	20.3	....
SE Bastian Bay plant and field, Plaquemines Parish, 4-21s-29e	150.0	74.0	5	....	....	....	....	....	6.1	....	....
Venice Plant, various fields, Plaquemines Parish, 25-21s-30e	1,000.0	592.0	2	....	194.6	47.4	53.8	....	....	130.6	[9]166.6
Kerr-McGee Corp.—Bayou Crook Chene plant and field, St. Martin Parish, 534-105-9e	12.5	NR	2	....	....	....	....	....	21.6	....	....
Dubach plant, Lincoln Parish, 526-&34-20n-3w	175.0	NR	2	....	66.1	26.1	37.5	....	..	....	[9]157.3 [4]24.8 [13]19.3
Koch Oil Co.—Bayou Postillion plant, Iberia Parish	25.0	12.0	5	....	....	....	....	....	....	0.4	....
Manchester plant, Calcasieu Parish	6.0	2.8	5	....	....	....	....	....	....	....	[13]4.8
LaGloria Oil & Gas Co.—Rayne plant and field, Acadia Parish, 11-9s-2e	176.0	57.4	2	35.8	....	....	....	....	83.9	....	[10]61.0
Liquid Products Recovery, Inc.—Bourg plant and field, Lafourche Parish	15.0	4.0	5	....	....	....	....	....	....	0.3	....
Napoleonville No. 1 plant and field, Lafourche Parish	30.0	8.0	5	....	....	....	....	....	....	1.3	....
Napoleonville No. 2 plant and field, Assumption Parish	11.0	6.0	5	....	....	....	....	....	....	....	....
South Grand Chenier plant and field, Cameron Parish	20.0	11.0	5	....	....	....	....	....	....	1.0	....
Vacherie plant and field, St. James Parish	10.0	4.0	5	....	....	....	....	....	....	0.5	....
Locust Ridge Gas Processing Co.—Locust Ridge plant, Locust Ridge, Buckhorn, and other fields, Tensas Parish, 21-10n-11e	20.0	6.0	NR	....	....	....	....	....	8.0	....	[9]1.2
Louisiana Land and Exloration Co.—Point Au Chien plant and field, Terrebonne Parish 18-19s-20e	125.0	60.0	3	44.9	31.2	11.7	11.7	....	....	19.7	[13]1.7
Marathon Oil Co.—Cotton Valley plant and field, Webster Parish, 26-21n-10w	220.0	67.0	2	102.2	43.5	14.7	14.7	....	....	....	[10]9.3
Mid Louisiana Gas Co.—Kenmore plant, College Point and St. James fields, St. James Parish, 44-12s-4	10.0	1.5	1	....	....	....	....	....	....	....	[10]0.2
Mississippi River Transmission Corp.—Perryville plant, Morehouse Parish	500.0	215.0	1	....	....	....	....	....	....	....	....
Mobil Oil Corp.—Cameron plant, various fields, Cameron Parish, 23-15s-13w	470.0	417.0	2&7	....	....	....	....	118.2	....	....	[9]202.2
Cow Island plant, various fields, Vermilion Parish, 29-3s-2e	825.0	457.0	2	....	....	....	....	....	366.5	....	....
Iowa plant, various fields, Jefferson Davis Parish, 18-95-6w	500.0	346.0	7	....	....	....	....	....	90.1	....	....
Riverside Fractionation plant, Ascension Parish, 49-9s-5e	....	....	(†)	....	(117.6)	(64.2)	(44.4)	....	....	(102.7)	[9](242.1)
Mullins & Prichard—*Burtville plant and field, East Baton Rouge Parish, 47-8s-1e	8.0	6.0	2&4	....	...	....	....	0.5	....	....	[13]1.5
Phillips Petroleum Co.—†Rollover plant, Gas Transmission Pipeline, Jefferson Davis Parish, nw4-11-11s-3w	190.0	NR	2	....	....	....	....	....	75.0	....	....
Vermilion plant, North Erath and Grosse Isle fields, Vermilion Parish, w4-se4-41-13s-4e	45.0	NR	2	....	....	....	....	....	25.0	....	....

Company, plant, location	MMcfd Gas capacity	MMcfd Gas through-put	Process method	Production—1,000 gal/day (Average based on the past 12 months) Ethane	Prop.	Isobut.	Normal or unsplit butane	LP-gas mix	Raw NGL mix	Debut. nat. gaso.	Other
Placid Oil Co.—*Black Lake plant and field, Natchitoches Parish, 14-11n-6w	150.0	160.0	2	....	....	....	....	....	363.9	....	[11]212.5
Lapeyrouse plant and field, Terrebonne Parish, 71-20-18e	100.0	43.0	2	....	....	....	....	....	49.5	....	[11]22.2
Patterson I plant, Patterson field, St. Mary Parish, 48-15s-11e	200.0	76.0	2	....	....	....	....	....	87.7	....	[11]27.5
Shell Oil Co.—Bayou Goula plant, Line Plant Field, Iberville Parish, 67-10s-12e	71.0	14.7	2	....	....	....	....	....	22.5	....	....
Black Bayou plant and field, Cameron Parish, 18-12s-12w	18.0	11.8	2	....	....	....	....	....	6.4	....	....
Calumet plant, 2-Line Plant field, St. Mary Parish, 11-12-51-52-15s-11e	1,200.0	1,211.2	2	....	....	....	....	....	782.1	....	....
Chalkley plant and field, Cameron Parish, 27-12s-6w	23.0	4.5	2	....	....	....	....	....	2.3	....	....
Crawfish pant, Line Plant field, St. Charles Parish, 36-13s-20e	120.0	91.7	6&7	....	....	....	....	....	106.5	....	....
Kings Bayou plant and field, Cameron Parish, 34-14s-7w	60.0	14.0	5	....	....	....	....	....	1.1	....	....
LaPice plant and field*, St James Parish, 38-12s-15e	12.0	10.3	5	....	....	....	....	....	0.2	....	....
Mermentau plant, Line Plant field, Acadia Parish, 70-10s-2w	120.0	40.5	2	....	....	....	....	....	42.1	....	....
Norco fractionator plant, Yscloskey & Toca fields, St. Charles Parish, 6-12s-8e	....	....	(†)	(695.1)	(434.3)	(127.9)	(144.8)	....		(219.6)	....
North Terrebonne plant, 2-Line Plant field, Terrebonne Parish, 20-29-33-17s-15e	1,250.0	1,315.3	2	(Liquids fractionated at Tebone plant)					1,131.0		
Tebone fractionator plant, North Terrebonne plant, Ascension Parish, 8&46-10s-2e	....	....	(†)	(351.2)	(343.9)	(106.8)	(96.7)	....	....	(232.3)	....
Timbalier Bay plant, Line Plant field, Terrebonne Parish, nw4 of 32-16 sw/4 of 33-19s-19e	100.0	53.9	6&7	....	....	....	....	....	81.8	....	....
Toca plant, Line Plant field, St. Bernard Parish, 54-14s-14e	830.0	478.3	2-6-7	....	....	....	....	....	610.2	....	....
Weeks Island plant and field, Iberia Parish, 13-14s-6e	129.0	57.3	2	....	12.2	....	....	....	26.0	....	....
West Lake Verret plant and field, St. Martin Parish, 15-14s-12e	60.0	9.8	6&7	....	....	....	....	....	7.7	....	....
Yscloskey plant, Line Plant field, St. Bernard Parish, 39-13s-15e	1,850.0	1,617.8	2	....	....	....	....	....	1,288.3	....	....
Sohio Petroleum Co.—*South Fields plant, Wilcox "B" Sand Unit, Beauregard Parish	10.0	10.0	3	....	....	....	....	12.0	....	....	....
Southern Natural Gas Co.—*Toca plant St. Bernard Parish, 56-14s-14e	525.0	386.0	5	....	....	....	....	....	39.4	....	....
South Louisiana Production Co. Inc.—Cocodrie plant, various fields, Evangeline Parish, 35-2s-2e	50.0	NR	2	....	22.5	....	16.8	....	....	11.1	[11]0.8
St. Landry plant, various fields, Evangeline Parish, 35-2s-2e	60.0	NR	2	....	24.4	....	16.3	....	....	10.8	[11]0.8
Sun Production Co.—Bayou Sale plant, Land Sand East field, St. Mary Parish, 14-16s-10e	16.0	12.7	2	....	....	....	....	....	11.2	....	....
Belle Isle plant and field, St. Mary Parish, 28-17s-10e	200.0	96.4	2	....	....	....	....	....	48.3	15.0	....
Delhi plant and field, Richmond Parish, 15-17n-9e	15.0	18.8	2	....	20.9	6.4	11.9	....	....	30.4	....
Fordoche plant and field, Point Coupee Parish 41-68-8e	50.0	22.1	2	....	....	....	....	....	33.2	....	....
Maurice plant and field, Lafayette Parish, 31-10s-4e	32.0	15.2	2	....	....	....	....	....	17.5	....	....
South Sarepta plant and field, Bossier Parish, 16-12s-4w	300.0	185.0	2&6	....	8.7	....	8.3	....	....	7.5	[11]19.1
Superior Oil Co.—Bayou Penchant plant and field, Terrebonne Parish, 2-19s-13e	75.0	78.0	5	....	....	....	....	....	7.5	....	....
Four Isle plant, Four Isle Dome field, Terrebonne Parish, 24-21s-16e	75.0	44.0	5	....	....	....	....	....	3.9	....	....
Gueydan plant, Southeast Gueydan field, Vermilion Parish, 21-12s-1w	30.0	15.0	5	....	....	....	....	....	0.1	....	....
Lowry plant, various fields, Cameron Parish, 16-12s-4w	300.0	185.0	2&6	59.8	63.1	23.2	14.9	....	....	33.0	*5.0
Tenneco Oil Co.—*Stephens plant, Haynesville field, Claiborne Parish, 6&7-13s-12e	35.0	18.0	2	....	3.0	....	2.9	....	....	4.7	....
Texaco Inc.‡—Alligator Bayou plant, Lake Fausse Point field, St. Martin Parish, sw14-34-10s-9e	27.0	NR	6&7	....	....	....	....	....	47.0	....	....
Floodway plant, St. Mary Parish, 16-16s-12e	900.0	NR	6&7	....	....	....	....	....	945.0	....	....
Fordoche plant and field, Pointe Coupee Parish, 28-6s-8e	30.0	NR	2	....	22.0	....	16.0	....	....	9.0	....
Henry plant, Vermilion Parish, 21-13s-4e	825.0	NR	2	346.5	283.5	93.0	....	....	420.0	....	....
Paradis plant, St. Charles Parish, 29-14s-20e	800.0	NR	2	200.0	429.0	....	237.0	....	....	205.0	....

Company, plant, location	MMcfd Gas capacity	Gas throughput	Process method	Production—1,000 gal/day (Average based on the past 12 months) Ethane	Prop.	Isobut.	Normal or unsplit butane	LP-gas mix	Raw NGL mix	Debut. nat. gaso.	Other
Sea Robin plant, Vermilion Parish, 21-13s-4e	900.0	NR	6&7	....	....	....	....	....	738.0	....	....
South Lake Arthur plant, Lake Arthur field, Jeff Davis Parish, 13-11s-3w	60.0	NR	6&7	....	....	....	....	....	122.0	....	....
Union Oil Company of California—Houma plant and field, Terrebonne Parish, 26-17s-17e	80.0	45.0	2	....	....	....	....	....	49.5	....	....
Union Texas Petroleum—Eunice plant, various fields, Acadia Parish	1,100.0	785.0	2	283.6	253.4	66.0	65.7	....	....	187.6	....
Rayne plant, various fields, Acadia Parish	750.0	725.9	2	107.6	131.3	36.4	34.0	....	76.3	....	....
Sligo plant and field, Bossier Parish	290.0	44.0	NR	....	14.4	4.9	5.0	....	....	15.6	....
Toca plant, various fields, St. Bernard Parish	190.0	92.0	2	....	56.0	16.6	18.7	....	....	36.4	....
United Gas Pipe Line Co.—Greenwood Dehydration plant, Greenwood field, Caddo Parish, 3-17n-16w	25.0	7.0	5	....	....	....	....	....	1.5	....	....
Warren Petroleum Co.—Johnson Bayou plant, Cameron Parish, 32-33-15s-12w	29.5	23.6	7	....	....	....	....	....	27.2	....	....
Total	**23,576.8**	**16,439.4**		**1,434.3**	**1,981.2**	**446.0**	**698.5**	**751.6**	**8,438.5**	**854.0**	**1,184.4**

†Fractionation. ‡All figures capacity, (Figures in parenthesis do not represent primary production, and are not added in state totals).
§Weathered natural gasoline.

MICHIGAN

Company, plant, location	Gas capacity	Gas throughput	Process method	Ethane	Prop.	Isobut.	Normal or unsplit butane	LP-gas mix	Raw NGL mix	Debut. nat. gaso.	Other
Amoco Production Co.— Kalkaska plant, Niagaran Reef Trend of North Michigan field, Kalkaska County, 31-27n-7w	100.0	89.8	6&7	....	....	....	....	....	91.0	....	....
Dow Chemical Co.—Beaver Creek Station, Beaver Creek Unit, Crawford County, 20-4w-25n	5.0	0.9	4	....	....	....	....	....	0.4	....	....
Marathon Oil Co.—Scipio plant and field, Hillsdale County, 2-55-3w	38.0	26.4	2	....	35.3	....	....	33.4	....	....	[11]0.5
Michigan Consolidated Gas Co.—Leonard plant and field, Oakland County, Addison 5n-11e	30.0	10.0	3	....	....	....	....	....	....	....	•10.0
Michigan Wisconsin Pipeline Co.—*Loreed plant and field, Osceola County, 30-18n-10w	54.0	25.0	2	....	4.4	2.2	0.7	....	....	2.9	....
Mobil Oil Corp.—Aurelius plant, Mason field, Ingham County, 36-2n-2w	23.0	19.5	2	....	17.7	....	....	....	25.9	....	....
Shell Oil Co.—Kalkaska plant, various fields, 32-27n-7w 6	350.0	162.0	2	....	....	....	....	....	498.0	....	[11]30.0
Sun Production Co.—Columbus Three St. Clair County, 3-5n-15e	2.3	NR	3	....	....	....	....	....	6.9	....	....
Total	**602.3**	**335.4**		....	**57.4**	**2.2**	**0.7**	**33.4**	**622.2**	**2.9**	**40.5**

MISSISSIPPI

Company, plant, location	Gas capacity	Gas throughput	Process method	Ethane	Prop.	Isobut.	Normal or unsplit butane	LP-gas mix	Raw NGL mix	Debut. nat. gaso.	Other
Enserch Exploration Inc.—Hurricane Lake and field, Lincoln County, se4-9-6n-6e	1.0	0.6	3	....	....	....	....	....	1.4	....	....
Exxon Co.—HUB FEU #2 field, Marion County	36.0	12.0	5	....	....	....	....	....	0.5	....	....
Getty Oil Co.—Bay Springs plant and field, Jasper County, 27-2n-10e	10.0	NR	2	....	....	....	....	8.0	6.0	....	....
Shell Oil Co.—Goodwater plant and field, Clarke County, 5-10n-8w	15.0	5.9	3	....	4.1	....	3.1	....	....	4.0	....
Tallahala Creek plant and field, Smith County, 5-1n-9e	10.0	5.3	3	....	5.1	....	5.1	....	....	4.3	....
Southern Natural Gas Co.—*Muldon Dehydration plant, Muldon Storage field, Monroe County, 27-15s-6e	750.0	317.0	5	....	....	....	....	....	21.8	....	....
Sun Production Co.—Mercer plant and field, Adams County, 16-9n-2w	0.7	0.4	3	....	....	....	....	....	1.3	....	....
Texas Oil & Gas Corp.—Harmony plant, various fields, Clarke County, 26-2n-14e	30.0	15.0	3	....	25.0	....	20.0	....	....	15.0	[11]6.0
Total	**852.7**	**364.2**		....	**34.2**	....	**28.2**	**8.0**	**31.0**	**23.3**	**6.0**

MONTANA

Company, plant, location	Gas capacity	Gas throughput	Process method	Ethane	Prop.	Isobut.	Normal or unsplit butane	LP-gas mix	Raw NGL mix	Debut. nat. gaso.	Other
Darenco Inc. —Culbertson plant, Big Muddy field, Roosevelt, 26-29n-55e	4.0	1.2	3	....	....	....	....	....	4.0	....	....
Sioux plant and field, Richland County 19-25n-58e	3.0	1.2	3	....	....	....	....	....	5.0	....	....
Sumatra plant, West Sumatra field, Musselshell County, 19-11n-32e	2.0	0.8	3	....	....	....	....	....	7.0	....	....
McCulloch Gas Processing Corp.—Fairview plant, Richland County, 10-42n-57e	6.0	3.0	2	....	6.0	....	....	12.0	....	....	....
Tule Creek plant and field, Roosevelt County, 14-30n-48e	2.5	0.5	3	....	2.5	....	....	5.0	....	....	....
Thunderbird Petroleums Inc.—Westco Refining Co.,											

Company, plant, location	MMcfd			Production—1,000 gal/day (Average based on the past 12 months)							
	Gas capacity	Gas through-put	Process method	Ethane	Prop.	Isobut.	Normal or unsplit butane	LP-gas mix	Raw NGL mix	Debut. nat. gaso.	Other
Cut Bank Sands field, Glacier County, 48-38-40—112-02-30	30.0	17.8	1	....	10.8	....	9.6	....	..	8.3	....
True Oil Co.—Bob Rhodes plant, 4-Mile Creek field, Richland County, 4-25n-58e	3.0	1.2	3	....	....	....	....	7.0	....	....	....
Union Texas Petroleum—Glendive plant, Pine-Cabin Creek field, Fallon County	5.8	2.8	1	....	11.0	....	....	....	....	14.3	....
Total	**56.3**	**28.5**		....	**30.3**	....	**9.6**	**24.0**	**16.0**	**22.6**	....
NEBRASKA											
Cities Service Co.—Kimball plant, various fields, Kimball County, 10-12n-55w	10.5	1.4	1	....	2.8	....	0.5	....	....	2.8	....
Marathon Oil Co.—West Sidney plant and field, Cheyenne County, 4-13n-50w	12.5	6.4	2	....	7.8	....	5.1	....	....	5.0	....
Total	**23.0**	**7.8**		....	**10.6**	....	**5.6**	....		**7.8**	....
NEW MEXICO											
Amoco Production Co.—*Empire Abo plant and field, Eddy County, 3-18s-27e	45.5	39.2	6&7	....	65.0	....	42.9	....	....	28.5	*96.0
Cities Service Co.—Bluitt plant, Chaveroo Tobac, Sawyer, other fields, Roosevelt County, 15-85-36e	37.0	34.0	2	16.1	33.5	4.5	11.1	....	..	12.1	....
*Empire Abo plant and field, Eddy County, 27-17s-27e	4.0	4.0	7	....	....	....	....	....	2.1	....	....
Continental Oil Co.—Maljamar plant and field, Lea County, 21-17s-52e	26.0	12.9	2	25.1	30.7	....	17.1	....	13.6	....	[11]0.3
El Paso Natural Gas Co.—Blanco plant, San Juan field, San Juan County, n2/n2-14-29n-11w	558.0	450.0	1	....	....	....	....	....	381.2	....	....
Chaco plant, San Juan field, San Juan County, sw4-16-26n-12w	594.0	536.9	2	....	....	....	....	....	702.2	....	....
Jal No. 1 plant, Lea County & Emperor field, Lea County, 37e-26s-36	303.0	247.9	2	....	....	....	....	....	79.7	....	....
Jal No. 3 plant, Langlie-Mattox & Blinebry fields, Lea County, nw4/sw4-33-24s-37e	225.0	134.2	2	....	....	....	....	....	162.8	....	....
Jal No. 4A plant, Blinebry-Jalmat fields, Lea County, se4/se4-32-23s-37e	185.0	155.9	1	....	....	....	....	....	136.3	....	....
Jal No. 4B plant, Lea County, se4/se4-32-23s-37e	....	....	(†)	....	(102.2)	....	(125.7)	....	....	(150.9)	....
San Juan River plant, San Juan Basin field, San Juan County, 1-29n-15w	71.0	55.5	1	....	11.4	....	17.2	....	....	18.4	....
Wingate plant, McKinley County, 16&17-15n-17w	....	....	(†)	....	(403.2)	(119.2)	(279.4)	....	....	(327.5)	....
Gas Company of New Mexico, division of Southern Union Co.—Avalon plant, Indian Basin field, Eddy County, 9-21s-27e	30.0	22.0	2	....	....	....	....	15.9		....	
Getty Oil Co.—Eunice No. 1-2 plant, various fields, Lea County, 27-22s-37e	150.0	NR	2	....	119.0	18.0	51.0	....	62.0	....	*94.0
Marathon Oil Co.—Indian Basin plant and field, Eddy County, 6-22s-24e	220.0	186.8	2	....	....	....	....	....	174.9	....	....
Northern Natural Gas Co.—Hobbs plant, Blineberry Tubb, Eumont, Jalmat fields, Lea County, 6-19s-37e	220.0	220.0	2	....	187.6	....	72.0	....	....	53.8	....
North Texas LPG Corp.—Lone Pine #1 plant, McKinley County	5.0	3.0	3	....	....	....	....	....	8.3	....	....
Lone Pine #2 plant, McKinley County	5.0	NR	3	....	....	....	....	....	....	....	....
Perry Gas Processors Inc.—Antelope Ridge plant, Lea County, Unit K-34-23-24	20.0	NR	1	....	....	....	....	....	....	....	....
Artesia plant, Eddy County	5.0	NR	1	....	....	....	....	....	....	....	....
Phillips Petroleum Co.†—Artesia plant, various pools, Eddy County, s2-se-4-7-18s-28e	43.0	NR	3&7	....	....	....	....	....	320.0	....	....
Eunice plant, Eunice, Seminole, Hobbs fields, Lea County, ne4-5-21s-36e	88.0	NR	3&7	....	....	....	....	....	450.0	....	....
Hobbs plant and field, Lea County, n2-nw4-4-19s-38e	38.0	NR	1	....	....	....	....	....	115.0	....	....
Lee plant, Vacuum and other fields, Lea County, sw4-se4-30-nw4-ne4-31-17s-35e	85.0	NR	1&3	....	....	....	....	....	245.0	....	....
Lovington plant, Lovington, San Andres & various fields, Lea County, sw4-31-16s-37e	10.0	NR	1	....	....	....	....	....	50.0	....	....
Lusk plant, Lusk and other fields, Lea County, nw4-ne4-19-19s-32e	60.0	NR	1&3	....	....	....	....	....	230.0	....	....
Wilson plant, Wilson and other fields, Lea County, ne4-5-21s-36e	6.0	NR	3	....	....	....	....	....	7.5	....	....
Southern Union Refining Co.—Kutz No. 1 plant, San Juan Basin field, San Juan County, 11, 12, 13, 14-28n-11w	100.0	105.0	2	....	....	....	....	....	230.0	....	....
Lybrock plant, San Juan Basin field, Rio Arriba County, 14-23n 7w	80.0	70.0	2	....	10.0	....	....	....	170.0	....	....
Texaco Inc.—Buckeye plant‡, Vacuum field, Lea County, 36&1-175&18s-34e	22.5	NR	6	....	....	....	....	....	144.6	....	....
Tipperary Corp.—Denton plant and field, Lea County	NR	5.0	3	....	....	....	....	....	30.0	....	....

	MMcfd			Production—1,000 gal/day (Average based on the past 12 months)							
Company, plant, location	Gas capacity	Gas throughput	Process method	Ethane	Prop.	Isobut.	Normal or unsplit butane	LP-gas mix	Raw NGL mix	Debut. nat. gaso.	Other
Warren Petroleum Co.—Eunice plant, Lea County, 3-22s-37e	NR	86.9	7	....	....	....	....	....	297.1	....	....
Monument plant, Lea County, 36-19s-36e	NR	81.1	7	24.1	40.2	....	....	3.1	72.7	16.0	....
Saunders plant, Lea County, 34-14s-33e	NR	28.2	1	....	....	....	....	....	146.3	....	....
Vada plant, Lea County, 34-14s-33e	NR	20.4	3	....	....	....	....	....	125.5	....	....
Total	**3,513.1**	**2,927.1**		**65.3**	**497.4**	**22.5**	**211.3**	**19.0**	**4,044.4**	**128.8**	**190.3**

†Fractionation. ‡All figures capacity.

NORTH DAKOTA

Company, plant, location	Gas capacity	Gas throughput	Process method	Ethane	Prop.	Isobut.	Normal or unsplit butane	LP-gas mix	Raw NGL mix	Debut. nat. gaso.	Other
Aminoil USA Inc.—Tioga plant, Tioga-Beaver Lodge fields, Williams County, 26-157n-95w	105.0	74.7	2	....	75.9	....	50.0	....	....	38.5	....
Darenco Inc.—Lignite plant and field, Burke County, 7-16n-91w	20.0	6.0	2	....	8.0	....	5.0	....	....	3.0	....
Kerr-McGee Corp.—Boxcar-Butte plant, McKinze County, s/2s-148n-102w	2.0	NR	2	....	1.0	....	....	....	1.5	....	....
True Oil Co.—Redwing Creek plant and field, McKensie County, 27-148n-101w	10.0	3.0	2	....	9.0	....	3.5	....	....	2.0	....
Total	**137.0**	**85.3**		....	**93.9**	....	**58.5**	....	**1.5**	**43.5**	....

OKLAHOMA

Company, plant, location	Gas capacity	Gas throughput	Process method	Ethane	Prop.	Isobut.	Normal or unsplit butane	LP-gas mix	Raw NGL mix	Debut. nat. gaso.	Other
Aminoil USA Inc.—Aline plant, Alfalfa County, 7-23n-11w	45.0	25.2	2	....	16.3	....	....	....	20.2	....	....
Fox plant, Fox-Milroy field, Carter County, 28-2s-3w	70.0	51.8	7	55.8	73.9	9.3	29.3	....	32.8	....	....
Lucien plant, Noble County, 18-20n-2w	6.0	6.0	3	....	....	....	....	....	9.1	....	....
Amoco Production Co.—Elmwood plant and field, Beaver County, 24-2n-24e	80.0	34.0	2	....	....	....	....	44.3	....	....	....
Hitchcock plant and field, Blaine County, 13-17n-11w	55.0	36.0	7	....	....	....	....	26.7	....	....	[11]0.2
Mooreland plant, Cedardale and other fields, Woodward County, 30-23n-18w	145.0	129.6	7	....	....	....	....	175.8	....	....	....
North Okarche plant and field, Kingfisher County, 8-15n-7w	25.0	21.0	1	....	....	....	....	....	2.2	....	....
Okeene plant and field, Blaine County, 36-19n-11w	39.0	33.0	2	....	....	....	....	....	16.7	....	[8]41.3 [11]0.9
Star Lacey plant and field, Blaine County, 2-19n-10w	20.0	7.0	2	....	....	....	....	....	5.1	....	[8]6.9
Anadarko Production Co.—North Richland Center plant and field, Texas County, 33-6n-12ecm	25.0	29.0	2	....	25.2	....	....	28.4	....	....	....
Atlantic Richfield Co.—Covington plant, Garber field, Garfield County, w2/sw4-19-22n-3w	15.0	12.6	7	....	....	....	....	....	35.6	....	[11]3.1
Drumright plant and field, Creek County, nw4/sw4-28-18n-7e	15.0	5.0	1	....	14.5	....	....	....	25.1	....	.....
Seminole plant and field, Seminole County, sw4/nw4-10-8n-6e	20.0	10.8	1	....	26.2	....	....	....	37.0	....	....
Cabot Corp.—Beaver plant, Beaver County, 25-5n-23ecm	35.0	20.7	2	....	7.9	....	8.7	....	7.8	....	....
Champlin Petroleum Co.—Enid plant, NE Enid field, Garfield County	62.0	24.0	2	....	....	....	....	91.7	....	9.1	....
Witcher plant and field, Oklahoma County	15.0	7.0	2	....	7.4	....	3.6	....	....	3.8	....
Chevron USA Inc.—Marietta plant, SE Marietta field, Love County, 31-75-3c	50.0	6.0	2	....	4.1	....	3.6	....	....	....	[11]1.0
Cities Service Co.—Ambrose plant, various fields, Kay County, 9-27n-1w	375.0	278.6	2	....	155.3	35.4	80.0	....	66.4	....	....
Garrett plant, NW Garrett field, Kay County, se4/5/34-27n-1e	6.7	1.1	2	....	....	....	....	....	2.6	....	....
Murdock plant, Mouser field, Texas County, 32-5n-16ecm	48.0	40.1	2	....	....	....	....	....	76.6	....	....
Rodman plant, various fields, Garfield County, 27-20n-8w	90.0	43.0	7	26.6	20.9	2.8	7.1	....	....	7.4	....
Colorado Interstate Gas Co.—Keyes plant and field, Cimarron County, e2 of se4-17-5n-7e	50.0	30.0	3	....	....	....	....	....	6.9	....	....
Continental Oil Co.—Hennessey plant and field, Kingfisher County, 36-19n-7w	30.0	23.3	6	....	....	....	....	86.8	....	....	....
Medford plant, Oklahoma Natural Gas field, Grant County, 32-27n-5w	30.0	22.8	2	....	3.7	1.2	2.5	....	2.5	....	....
CRA Inc.—Lamont plant, Grant County, 20-26n-3w	12.5	6.3	2	....	5.5	....	2.3	....	....	3.7	....
Dorchester Gas Producing Co.—Hooker plant, Hugoton field, Texas County, 8-4n-17ecm	125.0	70.0	1	....	42.0	8.5	25.0	....	....	21.0	....
Eason Oil Co.—Plant No. 3, Cresent, Lovell, and Hennessey fields, Logan County, 34-17-4w	32.0	12.0	1	....	14.0	....	2.4	....	15.1	....	....
El Paso Natural Gas Co.—Beaver plant and field, Beaver County, se4/ne4-18-3n-26e	40.0	20.2	3	....	....	....	....	....	17.0	....	....
Enserch Exploration Inc.—Katie plant, Garvin County, 36-2n-2w	20.0	5.5	2	....	....	....	....	....	10.1	....	....
Wallville plant, Garvin County, 27-4n-3w	6.0	3.7	2	....	....	....	....	....	4.1	....	....
Excelsior Oil Corp.—Tyrone plant, Hugoton, Dombey & Camrick fields, Texas County, 19-6-19	66.0	50.0	2	....	....	....	....	....	90.0	....	...

	MMcfd			Production—1,000 gal/day (Average based on the past 12 months)							
Company, plant, location	Gas capacity	Gas through-put	Process method	Ethane	Prop.	Isobut.	Normal or unsplit butane	LP-gas mix	Raw NGL mix	Debut. nat. gaso.	Other
Exxon Co. USA—Camargo plant, Putnam field, Dewey County, 10-18n-19w	15.0	10.6	2	....	10.0	8.0	....	....	....	....	....
Dover-Hennessey plant and field, Kingfisher County, 1-18n-7w	107.0	90.0	2	....	....	....	....	....	269.0	....	....
Getty Oil Co.—East Velma Middle Block plant, various fields, Stephens County, 4-2s-4w	30.0	NR	2	....	....	....	....	....	....	40.0	....
Marlow plant, West Marlow field, Stephens County, 11-2n-8w	15.0	NR	2	....	....	....	....	....	6.0	....	....
Velma plant and field, Stephens County, 23-1s-5w	70.0	NR	2	....	....	....	....	....	109.0	48.0	[11]1.0
Grimes Gasoline Co.—Okemah plant and field, Okfuskee County, se4-23-11-9	1.0	0.6	4	....	....	....	....	....	....	1.0	....
Kerr-McGee Corp.—Milfay plant, Creek County, 21-15n-7e	12.0	NR	2	....	5.2	....	2.0	....	....	3.6	....
Koch Oil Co.—Fitts plant, Fitts & Jesse fields, Pontotoc & Coal Counties, 30-2n-7e	3.5	1.6	3	....	1.1	....	....	....	....	2.7	....
Ladd Petroleum Corp.—Leonel plant, SW Canton field, Dewey County, nw4-14-16n-14w	26.0	26.0	3	0.3	10.8	2.3	4.5	....	....	....	[1]1.3 [2]2.4
Mapco Inc.—Tyrone plant, Hugoton field, Texas County, 11-6n-18e	65.0	50.0	2	....	....	....	....	....	41.2	....	....
Mobil Oil Corp.—Chitwood plant, various fields, Grady County, 34-5n-6w	60.0	35.5	2	....	....	....	....	....	86.1	....	....
Northeast Trail plant, Putnam field, Dewey County, 1-17n-18w	25.0	11.4	2	....	21.5	....	....	....	23.2	....	....
Postle Hough plant, Hough field, Texas County, 13-5n-13ecm	18.5	9.4	2	....	....	....	....	....	46.9	....	....
Putnam Oswego plant, West Crane and Putnam fields, Dewey County, 35-16n-16w	50.0	56.3	2	....	21.6	....	....	....	29.5	....	....
Seiling plant and field, Woodward County, 32-20n-17w	20.0	8.3	3	(All products fractionated at N. E. Trail)							
Sholem Alechem plant, Sho-Vel-Tum field, Stephens County, 2-1s-4w	70.0	51.8	6	....	7.9	....	....	....	143.5	....	....
Taloga plant, Putnam field, Dewey County, 30-18n-17w	15.0	2.6	2	(All products fractionated at N. E. Trail)							
West Putnam plant, Putnam field, Dewey County, 9-17n-17w	11.0	2.8	3	(All products fractionated at N. E. Trail)							
Mustang Gas Products Co.—Calumet plant, Watonga Trend field, Canadian County, nw¼-nw¼-27-14n-9w	250.0	202.0	2	....	34.2	....	....	....	68.7	....	....
Northern Natural Gas Co.—Cabot-Highland plant, Anadarko field, Beaver County, 18-4n-27e	50.0	10.0	5	....	....	....	....	....	....	1.5	....
Phillips Petroleum Co.†—Bradley plant and field, Garvin County, ne4-nw4-18-4n-4w	140.0	NR	1	....	....	....	....	....	250.0	....	....
Cimarron plant and field, Woodward County, e2-ne4-27-20n-17w	56.0	NR	3	....	....	....	....	....	112.0	....	....
Edmond plant and field, Oklahoma County, w4-se4-31-14n-3w	150.0	NR	1	....	....	....	....	....	260.0	....	....
Natura plant and field, Okmulgee County, ne4-ne4-ne4-17-15n-13e	2.0	NR	3	....	....	....	....	....	3.0	....	....
Norge plant, Northwest Norge field, Grady County, ne4-3-6n-8w	27.0	NR	3	....	....	....	....	....	160.0	....	....
Okla plant, Oklahoma City field, Oklahoma County, ne4-sw4-1-11n-3w	16.0	NR	1	....	....	....	....	....	60.0	....	....
Sooner #1 plant, Sooner field, Major County, se4-se4-se4-17-20n-9w	12.0	NR	3	....	....	....	....	....	20.0	....	....
Pioneer Gas Products Co.—Binger plant and field, Caddo County, 26-10n-11w	15.0	3.2	7	....	....	....	....	18.3	....	....	....
Madill plant, Cumberland field, Marshall County, 32-7e-5s	27.0	20.1	2	....	26.0	2.3	....	....	....	16.8	....
Ringwood plant and field, Major County, 11-22n-10w	80.0	60.1	2&7	....	....	....	....	147.8	....	....	....
Shell Oil Co.—Seiling plant, Ellis, Dewey, Gage et al fields, Dewey County, 4-19n-17w	75.0	44.0	2	....	41.0	....	....	....	37.0	....	....
Sohio Petroleum Co.—Elmore plant, Eola field, Garvin County, 17-1n-1w	75.0	75.0	1&2	....	12.0	....	27.0	....	....	2 0.0	[6]75.0
Norman plant, East Washington field, McClain County	5.0	4.0	3	....	1.0	....	....	....	....	3.0	....
Sun Production Co.—Carney plant, Fallis field, Lincoln County, 12-15n-2e	17.5	3.2	2	....	....	....	....	....	6.8	....	....
Goldsby Central plant, several fields, McClain County, 3-7n-3w	45.0	37.4	7	....	....	....	....	....	125.6	....	....
Laverne plant and field, Harper County, 20-26n-25w	225.0	184.2	7	....	85.0	16.8	44.4	....	....	58.0	[9]245.7 [11]4.9
Steedman plant, Allen field, Pontotoc County, 36-5n-7e	3.0	0.7	3	....	1.8	....	....	....	1.7	....	....
Tonkawa plant, Tonkawa SE field, Kay County, 30-25n-1e	2.0	0.5	3	....	....	....	....	....	2.0	....	....
Wakita plant, several fields, Grant County, 5-27n-7w	15.0	9.3	2	....	....	....	....	....	30.1	....	....
Tenneco Oil Co.—Ames plant, Major County, se¼ of sw¼-12-20n-10w	65.0	50.0	2	....	....	....	....	....	87.9	....	....

	MMcfd			Production—1,000 gal/day (Average based on the past 12 months)							
Company, plant, location	Gas capacity	Gas throughput	Process method	Ethane	Prop.	Isobut.	Normal or unsplit butane	LP-gas mix	Raw NGL mix	Debut. nat. gaso.	Other
Texaco Inc.‡—Apache plant and field, Caddo County, 2-5n-12w	7.5	NR	3	....	3.0	....	....	7.0	....	....	....
Camrick plant and field, Beaver County, 31-1n-20ecm	45.0	NR	2	....	....	....	....	....	88.7	....	....
Enville plant, SW Enville field, Love County, 7-7s-3e	23.0	NR	2	....	10.3	....	6.5	....	....	6.2	....
Texas Oil & Gas Corp.—Cimarron plant, various fields, Blaine County, 24-18n-34w	90.0	85.0	7	....	....	....	....	....	150.0	....	....
Custer plant, various fields, Custer County, 24-14n-16w	50.0	35.0	2	....	21.0	....	....	23.0	....	....	....
Jefferies plant, various fields, Major County, 14-23n-12w	20.0	5.0	2	....	....	....	....	....	13.0	....	....
Union Oil Company of California—Caddo plant and field, Carter County, 23-3s-1e	10.0	7.5	3	....	8.1	....	....	....	7.2	....	....
Union Texas Petroleum—Chaney Dell plant, various fields, Major County	100.0	60.8	2	....	....	....	....	....	112.9	....	....
Warren Petroleum Co.—Knox plant, Knox Bromide field, Grady County, 33-3n-5w	NR	21.2	1	....	7.3	....	....	....	0.9	....	[10]37.7
Maysville plant, Golden Trend field, Garvin County, 18-4n-2w	NR	60.7	7	....	47.7	7.2	31.1	....	....	38.8	[6]52.5
Mocane plant, Beaver County, 18-5n-25e, ecm	NR	113.7	2	....	12.6	24.5	....	....	45.4	....	[9]91.6
Total	**4,209.8**	**2,990.4**		**82.7**	**853.3**	**118.3**	**278.7**	**648.4**	**2,689.4**	**283.3**	**565.5**

†All figures are capacity

PENNSYLVANIA

Company, plant, location	Gas capacity	Gas throughput	Process method	Ethane	Prop.	Isobut.	Normal or unsplit butane	LP-gas mix	Raw NGL mix	Debut. nat. gaso.	Other
Seneca Co.—Lamont plant and field, Elk County	3.0	2.4	1	....	....	....	....	....	....	0.5	....
Van plant and field, Venango County	2.0	0.8	1	....	2.4	....	1.1	....	....	1.0	....
Total	**5.0**	**3.2**		....	**2.4**	....	**1.1**	....	....	**1.5**	....

SOUTH DAKOTA

Company, plant, location	Gas capacity	Gas throughput	Process method	Ethane	Prop.	Isobut.	Normal or unsplit butane	LP-gas mix	Raw NGL mix	Debut. nat. gaso.	Other
McCulloch Gas Processing Corp.—Belle Fourche plant, Butte County, 24-12n-1e	38.0	12.0	2	....	7.0	....	....	7.7	....	....	....
Total	**38.0**	**12.0**		....	**7.0**	....	....	**7.7**	....	....	....

TEXAS

Company, plant, location	Gas capacity	Gas throughput	Process method	Ethane	Prop.	Isobut.	Normal or unsplit butane	LP-gas mix	Raw NGL mix	Debut. nat. gaso.	Other
Adobe Oil Co.—Sale Ranch plant, Spraberry Trend field, Martin County, 23-1n-37	NR	12.0	2	....	....	....	....	....	76.2	....	....
Aluminum Company of America—Alcoa plant, various fields, Calhoun County	150.0	90.0	2	....	....	....	....	....	49.5	....	....
Amerada Hess Corp.—Adair plant and field, Terry County, 5-C37-PSl	5.0	4.7	3&4	....	17.5	....	12.0	....	....	7.6	....
Aminoil USA Inc.—Birthright plant, Birthright, Brantley-Jackson fields, Hopkins County	30.0	7.9	2	....	7.6	....	....	....	13.1	....	....
Amoco Gas Co.—Texas City extraction plant, Galveston County, John Grant A-72	140.0	123.0	3	24.8	15.4	....	....	40.2	26.7	....	....
Amoco Production Co.—Anton Irish plant and field, Hale County, 14-DT-HE & WT RR	16.0	3.2	3	....	....	....	....	....	30.5	....	....
Burnell-North Pettus plant and field, Bee County, A-591	130.0	79.6	1	17.8	15.9	....	9.0	0.4	22.1		[10]0.6
East Bay City plant and field, Matagorda County, 5-4-3	150.0	18.0	5	....	....	....	....	....	....	....	[12]2.7
Edgewood plant and field,* Van Zandt County, Z. Roberts-A 702	60.0	21.8	2	....	17.0	....	....	....	86.0	....	....
Hastings plant and field, Brazoria County, 1-ACH+D-A 416	70.0	73.5	6&7	....	....	....	....	....	30.0	....	[6]54.0
LaBlanca plant and field, Hidalgo County, Tex-Mex RR	50.0	21.1	4	....	....	....	....	....	....	....	[12]3.2
LaRosa plant* and field, Refugio County, Jose M. Aldrete	16.0	9.0	3	....	....	....	....	....	....	....	[12]2.5
Levelland plant and field, Hockley County, Labor 7, League 72, Val Verde Co. School Land	40.0	19.8	1	....	57.9	....	30.0	....	....	23.6	....
Luby plant, Luby-Petronia field, Nueces County, Canutillo Colony Dutch Co.	90.0	32.7	2	....	7.5	....	12.7	....	....	12.3	[7]20.1 [14]0.8
Midland Farms plant and field, Andrews County, 8-42-T-T-N G&MMB&A	45.0	32.5	6&7	....	....	....	....	....	128.0	....	....
Monahans plant and field, Winkler County, 24-10-PSL	5.0	5.4	3	....	....	....	....	....	....	....	[11]12.0
North Cowden plant, Cowden field, Ector County, 34-35-43-1m-T&P Ry	45.0	43.2	6&7	....	78.3	....	55.0	....	....	51.5	[6]115.0
Old Ocean plant and field, Brazoria County, Charles Breen League A46	570.0	261.0	2	149.0	97.0	30.0	28.0	....	....	92.0	[1]16.0
Prentice plant and field, Yoakum County, 20K PSL	6.0	5.1	1	....	....	....	....	....	33.0	....	....
Ropes plant and field, Hockley County, 12-5 Wilbarger County School Land	2.0	1.1	3	....	....	....	....	....	....	....	[12]8.7
Slaughter plant and field, Hockley County, 14-15-49 Edwards & Scurry County School Land	80.0	38.4	1	....	121.0	....	79.0	....	....	63.0	[6]64.3

Company, plant, location	MMcfd			Production—1,000 gal/day (Average based on the past 12 months)							
	Gas capacity	Gas through-put	Process method	Ethane	Prop.	Isobut.	Normal or unsplit butane	LP-gas mix	Raw NGL mix	Debut. nat. gasø.	Other
South Fullerton plant, Fullerton field, Andrews County, 8-A 48-PS1	10.0	9.6	6&7						93.0		
South Gillock plant* and field, Galveston County, John Sellers	32.0	25.6	2						9.2		[9]13.1
West Yantis plant* and field, Wood County, 3-Oscar Engleton A 181	50.0	15.6	3								[11]71.7
Willamar Miocene plant, Willamar West, Miocene G.U. field, Willacy County, A. J. Jones Estate Share 13	110.0	12.7	5								[11]0.3
White Flat plant and field, Nolan County, John Clark-A 287	6.5	2.3	3								[11]19.0
Anchor Gasoline Corp.—Tabasco plant and field, Hidalgo County, NW corner of Tract 322, Las Ejidas de Reynosa Vieja Grant	67.0	NR	1					11.0	3.8		
Arkansas Louisiana Gas Co.—Jefferson plant and field, Marion County, Heirs of John Haniss A-188	3.5	0.9	5								[11]0.5
Waskom plant, various fields, Harrison County, J. Blair	205.0	50.0	2		18.0	7.0	9.5			33.5	[9]1.5 [9]1.0 [10]2.0
Willow Springs plant, Willow Springs-Manziel field, Gregg County, P.P. Rains	20.0	7.8	5							3.0	
Atlantic Richfield Co.—*Block 31 plant and field, Crane County, 33-31	130.0	136.6	2	0.2	106.4		57.1			45.6	[11]209.4
Crane plant, Wilshire field, Upton Count,, 128-DCCS&RRNG RRCo.	15.0	10.5	3	7.2	7.9		4.8			4.0	[11]0.1
Crittendon plant and field, Winkler County, 24-e23-PSL	50.0	33.0	7	29.9	16.0	3.6	4.4			7.2	
Dayton plant and field, Liberty County, 7 HT&BRR	70.0	27.0	2	17.6	12.9	3.6	3.7			6.3	
East Rhodes plant and field, McMullen County, Seale & Morris 9-A 441	12.0	3.0	5								[11]2.3
Eldorado plant, Hulldale field, Schleicher County, 81-TTTC RR	50.0	29.5	1		36.6		19.7	53.6		12.9	[11]7.1
Fashing plant, Edwards Line Fashing field, Atascosa, Karnes County, 131 Wm Smith	12.0	7.5	1					1.2	1.6		[11]1.8
Hull plant, Hull-Merchant field, Liberty County, William Smith A-342	18.0	5.0	2		2.4					3.3	
Longview plant, East Texas field, Gregg County, J. Moseley	35.0	17.0	2&6	19.2	88.7				110.5		
Midland plant, Pegasus field, Midland County, 17-40-4s-T&PRR	10.0	9.6	3	4.1	5.8		3.9			3.4	[10]0.1
Northeast Thompsonville plant and field, Jim Hogg County, 4r Holheim subdivision La Animas GT Pena Tracts A-244	100.0	35.0	5								[11]4.9
Nueces River plant, various fields, Live Oak County, Cameron CSL 32-A-34	90.0	33.0	2	3.0	18.0		9.0			7.0	
Price plant, East Texas field, Rusk County, J. B. Cadena	15.0	3.0	1		15.5		15.5			19.2	
Refugio plant and field, Refugio County	6.5	4.5	3						1.5		
Roos Field Center plant, Roos field, McMullen County, Chas. T. Stansel 102-A-1141	42.0	10.0	5								[11]7.8
Silsbee plant and field, Hardin County, George W. Brooks A4	50.0	20.0	2	10.5	10.5	4.6	5.1			13.3	
South Hampton plant and field, Hardin County, F. Simmons A451	25.0	5.0	1		1.4		1.0			2.1	
Taft plant, East White Point field, San Patricio County, 48 & 48A Coleman Fulton Pasture Lands	40.0	22.0	2		4.0		3.0			5.0	
Beacon Gasoline Co.—Strawn plant, H. J. Strawn field, Tom Green County	7.0	6.5	3						25.0		
Blackhawk Gasoline Corp.—Game plant, County Reg field, Jack County, 9 miles east of Graham	700.0	400.0	3&4					0.9		0.6	
Breckenridge Gasoline Co.—Eliasville plant, Stephens County Regular field, Stephens County, TE&L Co. 1174	5.0	2.0	2		2.8		1.9			2.6	
Lodi plant, Rodessa field, Cass County, Wm. R. Meyers #1-166	5.0	3.4	1						6.6		
Cabot Corp.—Estes plant, North Ward field, Ward County, 3-16, University Lands	11.5	7.5	6						45.6		
Walton plant, Kermit field, Winkler County, 11-26-PSL	33.5	21.2	6						66.9		
Champlin Petroleum Co.—Conroe plant and field, Montgomery County	65.0	66.0	7						146.3		
East Texas plant, Carthage & Bethany fields, Panola County	220.0	170.0	7	40.5	44.1		38.5			101.5	
Gulf Plains plant, Stratton-Agua Dulce field, Neuces County	250.0	131.0	2	62.9	48.9	14.9	14.9			75.2	
Chevron USA Inc.—Chevron plant and field, Kleberg County, Lat. 27°25′ Long. 97°17′	80.0	15.0	5						2.1		[11]18.3
Kermit plant and field, Winkler County	50.0	17.0	2		5.0		8.9				
North Snyder plant, Snyder field, Scurry County	44.0	43.0	3	103.9	163.3	18.6	62.2		53.5		

	MMcfd			Production—1,000 gal/day (Average based on the past 12 months)							
Company, plant, location	Gas capacity	Gas through-put	Process method	Ethane	Prop.	Isobut.	Normal or unsplit butane	LP-gas mix	Raw NGL mix	Debut. nat. gaso.	Other
Sherman plant and field, Grayson County	40.0	22.0	2	....	15.6	....	....	17.7	....	9.2	....
Sivells Bend plant and field, Cooke County	5.0	1.0	1	....	0.7	....	....	0.9	0.5	....	....
Cities Service Co.—Chico plant, various fields, Wise County, GH&HRR Co. A-384	55.0	45.0	2	80.9	95.2	5.5	31.2	....	....	29.1	....
Corpus Bay plant, Corpus Christi Bay field, San Patricia County, Lot 9, Gregory Sub'd, Geronimo Valdez A-296	75.0	38.0	2	17.6	13.1	7.1	4.2	....	....	6.9	....
East Texas plant and field, Gregg County, Wm. Castleberry A-38	27.0	20.5	2	38.3	74.3	....	55.8	....	....	34.6	....
Ector plant*, Harper Devonian field, Ector County, 28-44-2s PPRRCS	4.0	2.5	7	....	....	....	....	....	5.2	....	....
Lefors plant, E&W Panhandle field, Gray County, 2-1, AC H&B	32.0	9.0	2	....	....	....	....	....	46.7	....	....
May plant and field, Kleberg County, Lot 12, Blk. 5, Gabriel Trevion, A-232	50.0	5.0	2	....	....	....	....	....	5.8	....	....
Myrtle Springs plant and field, Van Zandt County, J. Saingva, A-765	30.0	15.0	2	....	7.4	....	7.6	....	....	3.8	....
Pampa plant*, Panhandle & White Deer fields, Gray County, 133 & 136 I&GNRR	50.0	18.0	2	....	30.0	3.3	13.4	....	....	18.5	....
Panola plant, West Carthage field, Panola County, Matthew Parker A-527	100.0	22.0	2	....	6.1	2.5	1.2	....	....	....	[1]41.6 [8]8.7
Roberts Ranch plant*, various fields, Midland County, 16-41-3s—T&PRR	95.5	80.0	2	....	....	....	....	....	135.7	....	....
Robstown plant and field, Nueces County, Simmons & Perry's Subv. of Fred Elliffer Tract	65.0	22.0	1	9.3	5.3	2.6	2.4	....	....	7.7	....
San Antonio Bay plant, North San Antonio Bay field, Calhoun County, Lot 11, Miguel Castillo A-7	12.4	7.9	2	2.9	3.2	1.3	1.3	....	....	2.1	....
Stonewall plant, various fields, Stonewall County, E. Borden A-831	20.0	4.8	2	....	18.9	....	10.6	....	....	6.5	....
Waco plant, various fields, McClennan County, J. D. Sanchez A-36	60.0	43.0	7	....	9.2	....	4.1	....	....	5.7	....
Welch plant, various fields, Dawson County, 67-Block M of EL&RRRR	2.5	2.3	3	....	....	....	....	....	25.2	....	....
West Seminole plant* and field, Gaines County, 335-GCCSD&RGNGRR	40.0	28.0	2	....	....	....	....	....	34.4	....	....
West World plant*, various fields, Crockett County, 19-AGCSFRR	15.0	5.5	2	....	5.4	....	2.8	....	....	1.6	....
Clark Fuel Producing Co.—South Kelsey plant and field, Starr County Tract 3-A Santa Teresa Grant	3.0	1.2	2	....	....	....	....	....	1.8	....	....
Sullivan City plant and field, Hidalgo County, Tract 238, Portion 40	20.0	0.8	3	....	....	....	....	....	....	....	....
Coastal States Gas Producing—Albany plant, Shackelford County	15.0	3.0	3	....	....	....	....	....	14.6	....	....
Freer plant, Webb County	190.0	81.0	2	....	12.5	....	19.1	....	....	11.7	....
Hidalgo plant, Hidalgo County	80.0	10.0	2	....	1.6	....	2.0	....	....	2.6	....
Mission plant, Hidalgo County	30.0	23.0	2	....	....	....	....	13.2	....	....	....
Coates, George H., Estate of—Jay Simmons plant and field, Starr County, San Jose Grant	5.0	2.0	1&2	....	....	....	....	3.0	....	....	[11]2.0
Colorado Interstate Gas Co.—Bivins plant, Panhandle field, Moore County, 33-PMc EL&RR	165.0	103.0	2	....	....	....	....	....	144.2	....	....
Fourway plant, Panhandle field, Moore County, s2 of sw4 49-6T T&RR	150.0	47.0	1	....	....	....	....	....	93.1	....	....
Continental Oil Co.—*Chittim plant*, Chittim Ranch field, Maverick County, N. J. Chittim Ranch	5.0	3.5	3	....	5.7	....	6.5	....	....	4.6	....
Hamlin plant, Round Top field, Fisher County, I&TC-1	20.0	8.7	3	(Liquids fractionated by others)				51.2	....	....	....
Port plant, Port Acres-Port Arthur field, Jefferson County, 14-10-RL	175.0	3.1	2	5.2	2.7	....	1.2	....	....	1.5	[11]0.1
Ramsey plant, Ford Sullivan field, Reeves County, 36-38-1	10.0	2.3	3	....	3.5	....	2.7	....	....	2.4	....
Rincon plant and field, Starr County, 485-CCSD-R6N6RR	33.0	17.2	5	....	6.8	....	6.3	....	....	9.9	....
CRA Inc.—Eldorado plant, Schleicher County, 33-MGH&SA	25.0	10.0	6&7	....	....	....	....	....	25.0	....	....
Mertzon plant, Irion County, Tom Green County School Land-#1	25.0	12.5	6&7	....	....	....	....	....	60.0	....	....
Quitman plant, Wood County, SG Purse A-456	30.0	5.7	1	....	5.8	....	13.0	....	....	10.5	....
Delta Drilling Co.—Ozona plant and field, Crockett County, MN-1	60.0	39.6	5	....	53.9	....	28.9	....	....	....	[11]36.6
Diamond Shamrock Corp.—McKee plant, Moore, Hugoton, Ochiltree fields, Moore County, 399-44-H&TC	375.0	322.0	2&6	....	284.9	52.6	116.9	....	....	138.9	[8]269.3
Dorchester Gas Producing Co.—Cargray plant, West Panhandle field, Carson County, 46-4-I&GN	100.0	33.0	1	....	17.1	7.4	16.9	....	....	14.8	[1]4.5 [8]22.0 [9]1.7
Sterling plant, Conger field, Sterling County, 10-22-H&TC	18.0	12.0	3	....	....	....	....	....	22.0	....	....
Texon plant, Big Lake field, Reagan County, 12-2-University	5.0	2.2	3	....	....	....	....	....	10.8	....	....

Company, plant, location	MMcfd Gas capacity	MMcfd Gas throughput	Process method	Production—1,000 gal/day (Average based on the past 12 months) Ethane	Prop.	Isobut.	Normal or unsplit butane	LP-gas mix	Raw NGL mix	Debut. nat. gaso.	Other
Woodlawn plant and field, Harrison County, L Watkins	100.0	8.0	1	0.1	4.3	....	4.0	....	....	....	[11]16.0
Eagle Petroleum Corp.—KMA plant, KMA, Wichita field, Wichita County	3.0	1.0	3	....	....	....	....	1.8	....	2.0	....
El Paso Natural Gas Co.—Midkiff plant, Spraberry field, Reagan County, nw4-nw2-sw4-22-T&PR Co.-97-55	168.0	82.9	1	88.4	168.1	....	76.7	....	....	62.9	....
Santa Rosa plant, Rosa-Ft. Stockton field, Pecos County, s2-105-B H&GRR Co.	30.0	16.1	1	....	....	....	....	....	28.2	....	....
Sealy Smith plant, Monhans, Yarbrough-Allen fields, Ward County, nw4-43A	17.0	9.1	4	....	....	....	....	....	3.1	....	....
Westlake plant, Lake Trammell field, Nolan County, e2-ne4-sw4-w2-nw4-se4-76-X T&P	25.0	10.6	1	....	....	....	....	....	40.0	....	....
Wilshire plant and field, Upton County, e2-ne4-ne4&ne4-se4-ne4-135-E CCS D&RGNGRR Co.	30.0	11.9	4	....	....	....	....	....	4.0	....	....
Enserch Exploration Inc.—Carlsbad plant and field, Tom Green County, Mason and Perry subdivision of Collyns Ranch	4.0	1.1	3	....	....	....	....	....	2.1	....	....
Gordon plant, Palo Pinto County, Thomas Reed A-384	50.0	37.1	7	....	....	....	....	....	123.6	....	....
Madisonville plant, Madison County, Alfred Gee A-16	20.0	10.7	5	....	....	....	....	....	1.4	....	....
Needville plant, Ford Bend County, Patrick H. Durst A-166	96.0	29.5	5	....	....	....	....	....	3.7	....	....
Pueblo plant, Eastland County, SP RR Co.-464	8.0	8.5	2	....	....	....	....	....	17.7	....	....
Ranger plant and field, Eastland County, H&TCRR-4-4	7.0	4.2	2	....	....	....	....	....	16.9	....	....
Red Oak plant, Leon County	10.0	3.1	5	....	....	....	....	....	0.5	....	....
Springtown plant, Parker County, J. L. Hodges A-690	75.0	66.7	7	....	....	....	....	....	250.5	....	....
Sonora plant, Sutton County, D. H. Corbin 6-JK A-1437 & 1433	90.0	26.6	7	....	....	....	....	....	17.1	....	....
Trinidad plant, Henderson County, North Addison A-17	65.0	64.3	7	....	....	....	....	....	88.1	....	....
Etexas Producers Gas Co.—Chapel Hill plant, Chapel Hill-Delaney field, Smith County	12.0	2.4	1	....	....	....	....	2.6	....	2.5	....
Exxon Co. USA—Amelia plant and field, Jefferson County, C. Williams	16.0	11.0	5	....	....	....	....	....	....	....	[11]0.7
Anahuac plant and field, Chambers County, H&TCRR-51 A-112	275.0	246.6	2	79.0	60.1	17.2	16.4	....	....	40.7	[11]4.2
Clear Lake plant and field, Harris County, James Lindsey	200.0	176.3	2	108.4	76.0	18.1	16.8	....	....	39.5	[11]2.1
Conroe plant and field, Montgomery County, R House	117.0	95.0	2-6-7	71.8	59.9	13.6	21.5	....	....	43.9	[11]7.6
East Texas plant and field, Rusk County, T. J. Martin	25.0	12.0	3	35.2	65.7	13.5	35.1	....	....	30.3	[11]2.7
Hawkins plant and field, Wood County, H. Watson	125.0	107.0	2	56.1	113.9	51.5	64.0	....	....	99.6	[11]12.3
Heyser plant and field, Calhoun County, Agaton Sisneros	22.0	16.0	5	....	....	....	....	....	....	3.7	....
Jourdanton plant and field, Atascosa County, Edward Estes	26.0	19.0	1	....	3.7	....	1.1	4.1	....	5.6	[10]3.7
Katy plant and field, Waller County, 110 A-332	1,260.0	734.1	2	541.9	179.3	46.0	46.3	....	....	181.8	[11]4.9
Kellers Bay plant and field, Calhoun County, N. Covassos League A-2	47.0	9.0	2	0.2	3.9	1.5	1.3	....	....	2.3	....
Kelsey plant and field, Brooks County, LaBlanca Grant A-459	250.0	110.0	2	52.0	55.2	17.6	18.4	....	....	....	[10]42.8
King Ranch plant, Seeligson field, Kleberg County, R. King 172	2,650.0	1,665.0	2	993.7	416.3	158.1	122.4	....	....	....	[10]429.2
Magnet Withers plant and field, Wharton County, Sylvanus Castleman	100.0	32.6	5	....	....	....	....	....	....	....	[11]2.0
Neches plant and field, Cherokee County, J. H. Shaw	40.0	23.0	2	15.7	31.2	6.3	16.0	....	....	19.5	[11]0.9
Northeast Loma Novia plant and field, Duval County, J .Poitevent 213 A-923	47.0	10.0	2	3.9	5.1	1.3	1.6	....	....	2.4	....
Pita plant and field, Brooks County	30.0	4.0	5	....	....	....	....	....	....	0.7	....
Pledger plant and field, Pledger County, W. C. Carson	200.0	176.0	6&7	36.2	27.8	8.4	....	....	....	68.0	[4]0.5 [10]0.3 [11]2.2
Pyote plant, Ward County, 32-16 University Lands	100.0	52.0	6	....	....	....	....	....	53.0	....	....
Sand Hills plant and field, Crane County, 17, 18, 19-32-13&22-27-PSL	60.0	64.0	2	....	....	....	....	....	108.0	....	....
Santa Fe plant and field, Brooks County, San Salvador del Tule A-290	47.0	16.0	2	8.6	5.8	2.6	1.8	....	....	....	[10]4.2
Sarita plant and field, Kenedy County, J. A. Balli A-2	255.0	94.0	2	60.4	25.6	9.5	8.6	....	....	....	[10]18.6
Sugar Valley plant and field, Matagorda County, Burnett & Sojourner	12.0	9.6	5	....	....	....	....	....	....	....	[11]0.6

Company, plant, location	MMcfd Gas capacity	MMcfd Gas throughput	Process method	Production—1,000 gal/day (Average based on the past 12 months) Ethane	Prop.	Isobut.	Normal or unsplit butane	LP-gas mix	Raw NGL mix	Debut. nat. gaso.	Other
Thompson plant and field, Fort Bend County, John Rabb	40.0	31.0	6&7	17.4	11.0	2.0	3.0	....	....	3.7	....
Tomball plant and field, Harris County, C. Goodrich	80.0	72.2	2	25.0	19.1	5.2	6.4	....	....	21.2	[11]3.9
Tom O'Connor plant and field, Refugio County, Maria Ximines A-324	150.0	112.0	1	....	17.0	10.2	11.3	....	....	29.4	[10]1.4
West Ranch plant and field, Jackson County, Ramon Musquez	23.0	18.1	3	....	....	....	....	....	....	....	[11]3.6
General Crude Oil Co.—Salt Creek plant and field, Kent County	28.0	20.0	4	....	....	....	....	....	1.4	....	....
Gerlane Petroleum Co.—Mobeetie plant and field, Wheeler County	NR	9.0	2	....	....	....	....	....	11.0	....	....
Getty Oil Co.—East Vealmor plant, various fields, Howard County, 20-27-H-2C	55.0	NR	2	....	144.0	16.0	78.0	....	....	62.0	[9]194.0
Headlee plant, Headlee Ellenburger field, Ector County, 41-2s-T&PRR	30.0	16.7	2	....	....	....	....	....	44.6	....	....
Headlee Devonian plant* and field, Ector County, 41-2s-T&PRR	120.0	140.0	2	....	....	....	....	....	251.2	....	....
Kingsmills, Schafer, Watkins plant, Panhandle field, Hutchinson, Carson, Gray Counties, 88-4-1 PN	220.0	NR	2	....	82.0	25.0	50.0	....	....	83.0	26.0
New Hope plant and field, Franklin County, Isaac Barre A-20	50.0	40.3	1	....	15.8	....	14.7	....	....	83.5	....
Normanna plant and field, Bee County, Thomas Duty	32.0	18.5	2	7.0	9.4	....	5.1	....	....	3.8	....
Spearman plant, Hansford field, Ochiltree County, 23-R-B-B	50.0	NR	2	....	28.0	....	....	....	35.0	....	....
Umbrella plant and field, Chambers County, TST 87-Galveston Bay	12.0	4.0	5	....	....	....	....	....	....	0.8	....
West Bernard plant and field, Wharton County, J. M. Rose Heirs	30.0	11.4	1	....	1.1	....	....	3.3	....	5.7	....
Grimes Gasoline Co.—North Dora plant and field, Nolan County, e2-45-20-T&RR	4.5	3.0	3	....	10.0	....	8.0	....	....	5.0	....
Gulf Energy & Development Corp.—Powell plant and field, Navarro County	15.0	9.0	1	....	....	....	....	....	....	....	....
Rio Grande City plant, various fields, Starr County	31.0	19.0	2	....	5.5	....	3.8	....	....	3.0	....
Runge plant, various fields, Karnes County	52.0	42.0	2	25.0	22.0	....	13.0	....	....	12.0	....
Houston Oil & Minerals Corp.—Smith Point Extraction plant, North Point Bolivar field, Chambers County, E. T. Branch A-40	150.0	105.0	5	....	....	....	....	....	7.5	....	[11]0.8
South Liberty Extraction plant, South Liberty field, Liberty County	18.0	12.0	3	....	....	....	....	....	3.0	....	....
HNG Petrochemicals Inc.—Bammel plant, various fields, Harris County, HT&BRA-A420	100.0	64.5	2	27.2	13.5	....	6.5	....	....	4.6	....
Gregory plant, various fields, San Patricio County, Geronimo Valdez A269	70.0	42.7	2	....	23.8	....	18.6	....	....	9.6	....
Liverpool plant, various fields, Brazoria County, Day Land & Cattle Co. A-601	24.0	10.0	2	....	....	....	....	....	6.1	....	....
Loma Blanca plant, various fields, Brooks County, Loma Blanca Grant-F. G. Chapa A98	25.0	10.2	2	....	....	....	....	....	11.2	....	....
Robstown plant, various fields, Nueces County, Mathis Garcia A116	75.0	17.1	2	13.8	10.2	....	65.7	....	....	4.3	....
Sonora plant, various fields, Sutton County, HE&WTRRA 352	50.0	52.9	2	....	....	....	....	....	64.2	....	....
Tuleta plant, various fields, Bee County, Brooks & Burleson	45.0	24.5	1	....	....	....	....	12.2	9.4	....	....
Victoria plant, various fields, Victoria County, James Reed A236	94.0	17.7	2	....	4.5	....	5.0	....	....	4.0	....
Hunt Estate, H. L.—*Pecos Valley plant and field, Pecos County, 3-H&TCRR	10.0	1.7	3	....	....	....	....	....	1.7	....	....
Hunt Oil Co.—*Fairway plant, Fairway James Lime Unit field, Henderson County, s2 G. E. Milner Tract, Jose Mora A-497	137.0	120.0	2	....	27.3	....	29.4	....	235.0	30.3	....
Indian Wells Oil Co.—Southwest Ozona plant and field, Crockett County, 2-2 I&GN	15.0	15.0	2	....	....	....	....	....	60.0	....	[11]6.5
Irion County Plant—Rocket B "II" plant, Spraberry Trend field, Irion County, nw4-78 H&TC 14	NR	10.0	3	....	....	....	....	....	401.0	....	....
Kerr McGee Corp.—Hobart Ranch plant, Hemphill County, 70-A-2 H&GN	43.5	NR	3	....	....	....	....	....	102.3	....	[11]23.7
Pampa plant, East Panhandle field, Gray County, 5163-3 I&GN	24.0	NR	2	....	....	....	....	....	48.7	....	....
Liquid Energy Corp.—Mineral Wells plant, Palo Pinto County	30.0	30.0	2	....	....	....	....	....	91.2	....	[11]4.2
Liquid Products Recovery Inc.—East Ramsey plant and field, Colorado County	15.0	7.5	3	....	....	....	....	....	....	5.5	....
LoVaca Gathering Co.—Bay City plant, Matagorda County	500.0	232.0	2	....	....	....	....	43.4	....	....	[9]87.8
Corpus Christi plant, Nueces County	200.0	162.0	2	40.6	50.4	25.9	23.6	....	....	34.0	....
Gohlke plant, DeWitt County	125.0	134.0	2	....	....	....	....	119.9	....	....	[9]57.4
San Antonio plant, Bexar County	120.0	107.0	7	....	12.2	....	....	27.3	26.3	....	....

Company, plant, location	MMcfd: Gas capacity	MMcfd: Gas throughput	Process method	Production—1,000 gal/day (Average based on the past 12 months): Ethane	Prop.	Isobut.	Normal or unsplit butane	LP-gas mix	Raw NGL mix	Debut. nat. gaso.	Other
Mapco Inc.—Westpan 950 plant, West Panhandle field, Hutchinson County, 92-Y2-TTRR	50.0	47.7	7						125.7		....
Westpan 1000 plant, West Panhandle field, Hutchinson County, 92-Y2-TTRR	145.0	105.4	7						215.3		....
Marathon Oil Co.—Markham plant, North Markham-North Bay City fields, Matagorda County, 4-9-9	165.0	112.8	2					89.3			....
Susan Peak plant and field, Tom Green County	1.5	1.8	3					3.0		2.9	....
Welder plant, Plymouth field, San Patricio County, 49-R. Montgomery 199 and Ewen Cameron A-97	55.0	26.9	1						6.2		....
Yates plant and field, Pecos County, 194-Scrap 1234-1	20.0	20.0	2		7.2			30.0			....
Matrix Land Co.—Box-Elmdale plant, Callahan field, Callahan County	NR	3.0	3						9.0		....
Tuscola plant, Taylor County Regular field, Taylor County	NR	1.0	3						2.0		....
Mobil Oil Corp.—Canadian plant, Northeast Canadian field, Hemphill County, NE corner of David Crockett	35.0	23.0	6						61.9		
Coyanosa plant* and field, Pecos County, 48 OWTTRR	550.0	240.6	2						166.7		[11]192.1
Desdemona plant and field, Eastland County, J. W. Carruth Farm W. M. Fundenburg	1.3	1.0	3					3.1		7.8	
Electra plant and field, Wilbarger County, 17-13 H&TCRR	1.4	0.8	3					6.1		5.3	
Kittie-Hagist complex, various fields, Duval & Live Oak Counties, Tract 53 Kittie George West Ranch subdivision	70.0	70.0	1	63.5	24.3		15.6			19.5	
La Gloria plant and field, Jim Wells County, 9-83 La Gloria subdivision	318.0	231.0	6	201.6	95.7	31.3	25.2			65.7	[11]17.0
*Pegasus plant and field, Midland County, e2-30-40-4s T&PRR	NR	80.4	2	83.1	66.6				76.9		
Seeligson plant* and field, Jim Wells County, Jaboncillas Grant A. Ramirena	318.0	223.0	6	165.6	58.0	16.5	13.9			56.6	[11]11.0
Vanderbilt plant, West Ranch field, Jackson County, R. Musquez A-59	88.0	92.0	2&5			....				37.3	[4]15.4
Waha plant and field, Pecos County, 5-C3 PSL	NR	138.3	2	....	....	....	....	..	230.9		....
Wilcox plant, Provident City field, Lavaca County, J. R. Ragsdale A-377	255.0	65.0	2	27.2	36.8	....	19.1	....		25.1	....
Monsanto Co.—Diamond "M"—Sharon Ridge plant and field, Scurry County, 182-97 H&TC	55.0	31.8	3	113.9	164.1	....	75.0		50.3		
Natural Gas Pipeline Co. of America—One Sixty-one plant, Panhandle field, Hutchinson County, s5-by2 TTRR Co.	242.0	134.1	5	....	....	....	....	....	1.1	....	....
One Sixty-two plant, Panhandle field, Moore County, 1 TTRR Co.	242.0	137.8	5	....	....	....	....	....	49.8	....	....
North Texas LPG Corp.—Barton Chapel plant, Jack County	15.0	14.0	7	....	....	....	....	....	47.0	....	[11]1.7
Eastland plant, Eastland County	2.0	1.0	3	....	....	....	....	....	2.0	....	....
Galveston plant, LaFitte's field, Galveston County	15.0	14.0	7	....	....	..	..	....	14.4	....	....
Huckabay plant, Erath County	15.0	14.0	7	....	....	....	....	....	21.3	....	[11]0.1
La Sal Vieja plant, Willacy County	15.0	7.0	7	....	....	....	....	....	9.6	....	....
Lone Camp No. 1 plant, Palo Pinto County	10.0	10.0	2	....	....	....	....	....	21.8	....	[11]0.6
Lone Camp No. 2 plant, Palo Pinto County	10.0	9.0	7	....	....	....	....	....	23.2	....	[11]0.5
Lone Camp No. 3 plant, Palo Pinto County	10.0	9.0	7	....	....	....	....	....	23.2	....	[11]0.5
Lone Camp No. 4 plant, Palo Pinto County	30.0	27.0	7	....	....	....	....	....	65.8	....	[11]1.6
Ponder No. 1 plant, Denton County	2.0	2.0	3	....	....	....	....	....	1.5	....	....
Ponder No. 2 plant, Denton County	2.0	2.0	6	....	....	....	....	....	1.5	....	....
Ranger No. 1 plant, Eastland County	5.0	4.0	3	....	....	....	....	....	8.1	....	....
Ranger No. 2 plant, Eastland County	10.0	4.0	7	....	....	....	....	....	8.1	....	....
Seven Oaks plant, Polk County	20.0	12.0	2	....	....	....	....	....	17.8	....	....
Sutton plant, Sutton County	10.0	10.0	7	....	....	....	....	....	22.6	....	[11]1.8
Northern Gas Products—Spraberry field, Martin County, 31-37-2n T&PRR	10.0	5.6	3	....	....	....	....	....	28.0	....	....
Sprayberry plant, Martin County, 4-HA	5.0	3.3	3	....	....	....	....	....	20.0	....	....
Northern Natural Gas Co.—Jasper plant, Puckett North Ellenberger field, Pecos County, CSL 16-19	35.0	12.0	2		....	....	....	....	7.0	....	....
Spearman plant, Hansford-Ochiltree fields, Ochiltree County, 23-B&RR	200.0	100.0	3	....	....	....	....	....	....	18.2	....
Odessa Natural Corp.—Foster plant, multi fields, Ector County, 18-42-2s-T&PRR	24.0	21.0	7	56.0	48.5	....	30.0	....	....	25.0	....
Ozona Gasoline Plant—Ozona plant and field, Crockett County, 13-TCRR R	4.0	3.0	3	....	....	....	....	....	6.0	....	....
Palo Pinto Oil & Gas Co.—Markley plant, Markley SE Marble Falls field, Jack County, SPRR A-583	4.0	1.0	3	....	....	....	....	....	7.7	....	....

	MMcfd			Production—1,000 gal/day (Average based on the past 12 months)							
Company, plant, location	Gas capacity	Gas through-put	Process method	Ethane	Prop.	Isobut.	Normal or unsplit butane	LP-gas mix	Raw NGL mix	Debut. nat. gaso.	Other
Parade Co.—Giles plant, East Texas field, Rusk County	7.5	3.9	1	....	31.6	....	....	....	12.0	....	....
Pecos Co.—Barnhart plant*, Barnhart and Farmers field, Reagan County, 5-HE&WT RR	25.0	6.0	1	....	6.6	....	3.7	....	....	3.7	....
Permian Corp.—Possum Kingdom plant, Iles North field, Stephens County, Edward Romershaven	5.0	2.5	3	....	....	....	....	....	7.5	....	....
Todd Ranch plant, Todd field, Crockett County, 28-WX GCD SFRY	5.0	1.8	3	....	....	....	....	....	15.0	....	....
Perry Gas Processors—Bakersfield plant, Pecos County	8.0	NR	1	....	....	....	....	....	....	....	....
Barstow plant, Ward County	25.0	NR	1	....	....	....	....	....	....	....	....
Dimmit plant, Dimmit County	10.0	NR	1	....	....	....	....	....	....	....	....
Hokit plant, Pecos County	25.0	NR	1	....	....	....	....	....	....	....	....
Howe plant, Ward County	75.0	NR	1	....	....	....	....	....	....	....	....
La Salle plant, La Salle County	20.0	NR	1	....	....	....	....	....	....	....	....
Pawnee plant, Bee County	20.0	NR	1	....	....	....	....	....	....	....	....
Pyote plant, Ward County	300.0	NR	1	....	....	....	....	....	....	....	....
Thompsonville plant, Jim Hogg County	50.0	NR	1	....	....	....	....	....	....	....	....
Petroleum Corp. of Texas—Ibex plant, Ibex, Shackelford Co. Regular field, Shackelford County, nw28-BAL	10.0	7.0	1	....	11.0	....	....	....	10.8	....	....
South Bend plant and field, Young County, J. Garrett	8.0	7.0	1	....	10.9	....	....	....	13.4	....	....
PGP Gas Products Inc.—Imperial plant, Abell and other fields, Crane & Pecos County, 21-1 H&TCRR	20.0	12.0	6&7	6.4	10.7	1.5	4.6	....	....	4.7	....
Phillips Petroleum Co.‡—Andrews plant, various fields, Andrews County, w2-nw4-19-A46-PSL	115.0	NR	1	....	....	....	....	....	400.0	....	....
Benedum plant, Pembrook, Stiles and other fields, Upton County, w2-se4-46-Y-MK&T	85.0	NR	1	....	....	....	....	....	270.0	....	....
Brazoria plant, Chocolate Bayou field, Brazoria County, nw4-5-HT&B-A221	55.0	NR	2	....	....	....	....	....	106.0	....	....
Canadian plant, West Panhandle field, Hutchinson County, nw4-se4-1-XO2-H&OB	18.0	NR	1	....	....	....	....	....	100.0	....	....
Crane plant, McElroy and other fields, Crane County, ne4-216-F-CCSD&RGNR RR	63.0	NR	2	....	....	....	....	....	300.0	....	....
Dumas plant, West Panhandle field, Moore County, nw4-181-44-H&TC	330.0	NR	1	....	....	....	....	....	550.0	....	....
Ector plant, Grayburg-Strawn field, Ector County, sw4-ne4-33-44-1n-T&P	40.0	NR	1	....	....	....	....	....	100.0	....	....
Fullerton plant, Fullerton and Shafer Lake fields, Andrews County, 17-A-32-PSL	55.0	NR	1	....	....	....	....	....	480.0	....	....
Goldsmith plant, Goldsmith, Harper-Penwell and other fields, Ector County nw4-se4-33-44-1n-T&P	370.0	NR	1-3-7	....	....	....	....	....	1,400.0	....	....
Gray plant, East Panhandle field, Gray County, e2-32-B2-H&GN	74.0	NR	1	....	....	....	....	....	250.0	....	....
Hansford plant, West Panhandle field, Hansford County, 7-8-1-PSL	170.0	NR	1	....	....	....	....	....	125.0	....	....
Henderson plant, North Henderson field, Rusk County, sw portion A. H. Crain (Anderson Tract)	370.0	NR	1	....	....	....	....	....	15.0	....	....
Luling plant, Branyon, Darst, Salt Flat, & Spiller fields, Caldwell County, North Corner, John Henry, Abst. 12	12.0	NR	3&7	....	....	....	....	....	60.0	....	....
North plant, East Panhandle field, Gray County, se4-sw4-35-nw4-ne4-36-3-1-I&GN	5.0	NR	1	....	....	....	....	....	52.0	....	....
Pantex plant, West Panhandle field, Hutchinson County, 8&9-M Whitley	40.0	NR	1	....	....	....	....	....	250.0	....	....
Puckett plant and field, Pecos County, n2-26-101-TC RR	250.0	NR	1	....	....	....	....	....	20.0	....	....
Rock Creek plant, West Panhandle field, Hutchinson County, nw4-22-y-A&B	150.0	NR	3&7	....	....	....	....	....	250.0	....	....
Sanford plant, West Panhandle field, Hutchinson County, s2-n2-w2-s2-82-46-H&TC	150.0	NR	1	....	....	....	....	....	270.0	....	....
Sherman plant, West Panhandle field, Hansford County, 7&8-1-PSL	340.0	NR	2	....	....	....	....	....	500.0	....	....
Sneed plant, West Panhandle field, Moore County, w2-nw4-Freeman Brazemore	250.0	NR	1	....	....	....	....	....	270.0	....	....
Sprayberry plant, Tex-Harvey & Azalea fields, Midland County, se4-25-3s-37-T&P	40.0	NR	1	....	....	....	....	....	300.0	....	....
Tunstill plant and field, Reeves County, ne4-ne4-10-2-56-T&P	28.0	NR	1	....	....	....	....	....	75.0	....	....
Pioneer Gas Products Co.—Arrington plant, Anadarko Basin field, Hemphill County, 62-A-2	40.0	42.1	2	....	....	....	....	54.8	....	....	....
East Goldsmith plant, Ector County, 34-34	50.0	15.1	2&7	....	....	....	....	49.0	....	....	....
Fain plant, West Panhandle field, Potter County, G&M 10-181-3	130.0	70.0	2	....	35.1	....	43.0	....	....	29.7	....

Company, plant, location	MMcfd Gas capacity	MMcfd Gas through-put	Process method	Ethane	Prop.	Isobut.	Normal or unsplit butane	LP-gas mix	Raw NGL mix	Debut. nat. gaso.	Other
Pampa plant, East Panhandle field, Gray County, H&GN 96-B-2	60.0	14.7	2		13.8				24.2		
Turkey Creek plant, West Panhandle field, Potter County, G&M 36-M-2	100.0	60.3	2		34.9		38.3			37.2	
Richardson, Sid Carbon & Gasoline Co.—Keystone plant* and field, Winkler County, 5-B-2 Public School Land	140.0	100.0	7		28.0		17.0			18.0	[8]105.0
Shell Oil Co.—Bryans Mill plant*, Bryans Mill, Frost, Carbondale and Lower Glen Rose fields, Cass County, B. F. Lynn A-651	70.0	67.3	2		48.9				73.2		
Conley plant, Conley, W. Odell, Thrash fields, Hardeman County, 80-H W&NW RR.	6.0	1.0	3		3.0		2.0			2.0	
Houston Central plant, Sheridan, Provident City, other fields, Colorado County, F. Mayhar A-400, K. Winn A589	425.0	205.2	2	181.3	148.7	34.1	44.6			40.3	[1]18.7 [11]96.4
Northwest Ozona plant and field, Crockett County, 46-OP GC&SF RR	10.0	8.0	3					15.0		5.0	
Person plant, Person and other fields, Karnes County, Jesus Hernandez A-140	54.0	28.5	2		16.0		11.2			10.6	[11]2.9
Tippett plant, Crossett, El Cinco, Tippett West fields, Crockett County, 28-31 H&TC RR	75.0	52.0	2&7	97.0	61.0				52.0		
TXL plant, TXL, Wheeler, Harper fields, Ector County, 17-45-1-ST&P RR	65.0	43.0	1	49.0	72.0		31.0			30.0	
Wasson plant, Wasson and Brahaney fields, Yoakum County, 827-D J. H. Gibson	175.0	154.0	1&2	214.0	443.0				480.0		
Southwest Forest Gas Gathering—Rocker B I plant, Spraberry Trend field, Reagan County	NR	13.0	3						42.0		
Stiles Plant Operators—Stiles plant, Spraberry Trend field, Reagan County	4.0	2.0	3						12.0		
Suburban Propane Gas Corp.—Lubbock County plant, Idalou Strawn Pool field, Lubbock County, N/2 59-A ELRA	0.6	0.2	3						1.8		
Martha F. Berry plant, West Big Foot Gas field, Frio County, M. C. Patton 1178 A-542	22.0	5.0	2		4.0		1.3			1.8	
Sun Production Co.—Big Wells plant and field, Dimmit County, I&gnrr-4-233-82-1	35.0	33.0	2		31.6	29.1				20.7	
Concho plant, several fields, Concho County, 153-72-T&NO	10.0	5.3	2					5.6	2.3		
Jameson plant and field, Coke County, 315-1A-H&TCRR	45.0	42.8	2	48.9	55.8		27.8			32.4	
Luby plant and field, Nueces County, 9-G Part Petronilla Ranch	10.0	4.9	NR					6.7	2.3		[11]1.7
Red Fish Bay plant, Redfish-Mustang field, San Patricio County, R. W. Williamson	140.0	39.7	2						27.1	12.6	
Shamburger plant, South Lake field, Smith County, John Lane A-557	1.0	1.2	3						4.6		
Snyder plant, Kelly Snyder field, Scurry County, 16-1 J. P. Smith	150.0	133.0	6		188.6	29.4	86.1		1,192.8	89.3	[11]1.1
Sun plant and field, Starr County, 239-AB225-CCSD4RGNGRR	88.0	84.4	3	44.5	51.1		30.1			49.0	[6]8.4
Tijerina-Canales plant, Tijerina-Canales-Blucher fields, Jim Wells County, 343-CCSD&RGNG	75.0	34.9	2		3.9		5.8		7.0		[8]16.4 [11]5.8
Victoria plant, several fields, Victoria County, Felipe Dimitt A-20	40.0	17.3	2						24.4		
West Helen Gohlke plant and field, Victoria County, 1-1 RR	40.0	12.3	2						19.5		
Superior Oil Co.—Portilla plant and field, San Patricio County, J. Francisco—E. Portilla—A-53	15.0	12.0	2					9.0		4.9	
Tenneco Oil Co.—Chesterville plant, Colorado County, 16-Wells Thompson A-708	55.0	30.0	2		17.5	4.9	6.0			8.8	
LaPorte plant, Harris County, Tract 55 Johnson Hunter League A-35	21.0	13.0	(†)		(4.5)	(3.2)	(2.9)			(2.3)	
Leabo plant, Matagorda County, sw¼-17 A-351	95.0	20.0	2						25.9		
Pearce plant, Aransas County, 64-65-66-76-77-78-88-89-90 Lamar	75.0	18.0	2	12.0					21.8		
Ward plant, McAllen field, Hidalgo County, Porcion 68, Gregorio Camacho A-28	140.0	40.0	2		11.3		9.2			15.5	[8]1.5
Texaco Inc.‡—Blessing plant, Matagorda County, 59-C J. E. Pierce H&GN	65.0	NR	2		20.0		15.0			47.3	
Encinitas plant, Brooks County, nw4 San Antonio Grant A214	17.0	NR	2						24.0		
Fuller plant, Scurry County, 642-97 H&TCRR	58.0	NR	2		58.0		46.0		227.5	59.0	

Production—1,000 gal/day (Average based on the past 12 months)

	MMcfd			Production—1,000 gal/day (Average based on the past 12 months)							
Company, plant, location	Gas capacity	Gas throughput	Process method	Ethane	Prop.	Isobut.	Normal or unsplit butane	LP-gas mix	Raw NGL mix	Debut. nat. gaso.	Other
Handy plant, Grayson County, se4 A-1441 IG&NRRCO	10.0	NR	2	....	....	....	....	....	48.6	....	....
Humble plant, Harris County, J. B. Stevenson Fee A-703 B-4	3.0	NR	3	....	....	....	....	....	11.0	....	....
Lamesa plant, Dawson County, 36-34-5n T&PRR	6.0	NR	3	....	10.0	....	....	....	15.0	....	....
Lockridge plant, Ward County, 101-34 H&TCRR	47.5	NR	2	....	....	....	....	....	21.1	....	....
Mabee plant, Andrews County, 32-40& 31-39-2n	20.0	NR	2	....	....	....	....	....	104.4	....	....
Ozona plant, Crockett County, 3-MN-GC&SERR	25.0	NR	3	....	....	....	....	....	73.5	....	....
South Kermit plant, Winkler County, 22-22 B-3 PSL	35.0	NR	2	....	7.3	....	....	....	33.0	....	....
Tijerina plant, Jim Wells County, A Canalas 300 A79	35.0	NR	2	....	....	....	9.3	....	....	....	*36.0
Texas Oil & Gas Corp.—Coyanosa plant, various fields, Pecos County, 18-143-T&STL	75.0	75.0	7	....	....	....	....	....	194.0	....	....
Denton plant, various fields, Denton County, BBB&CRR A-175	30.0	11.0	2	....	....	....	....	....	30.0	....	....
East Texas plant, various fields, Marion County, John H. Kernals A-235	75.0	75.0	7	....	25.0	20.0	....	....	....	20.0	....
Laredo plant, various fields, Webb County, Porcion 14 N. D. Hachar East	30.0	7.0	2	....	....	....	....	10.0	....	3.0	....
Shackelford plant, various fields, Callahan County, SYR 23&24 B.D.H. Lands	30.0	15.0	2	2.0	15.0	....	8.0	....	....	40.0	....
Tipperary Corp.—Bowie plant, Montague County	NR	3.0	1	....	....	....	....	....	....	....	....
Claytonville plant, Fisher County	NR	13.0	2	....	....	....	....	....	143.0	....	....
Tuco Inc.—Carson County plant, Panhandle field, Carson County, 4-5 I&GN PR	20.0	NR	7	....	....	....	....	....	23.8	....	....
Union Oil Co. of California—Bakke plant and field, Andrews County, 20-A44-PSL	19.0	5.4	2	....	....	....	....	....	39.9	....	....
Dollarhide plant and field, Andrews County, 25-A52-PSL	75.0	38.1	1	....	56.7	....	29.6	....	25.6	....	....
Fort Trinidad plant* and field, Houston County, RCS-A-23	40.0	24.1	2	....	14.7	....	10.7	....	9.4	....	....
Van plant and field, Van Zandt County, JWS A-891	15.0	12.5	2	....	27.4	....	30.0	....	26.8	....	....
Union Texas Petroleum—Benedum plant, Spraberry Trend and various fields, Upton County	55.0	16.1	2	15.5	36.7	3.4	11.8	....	....	15.5	....
Marrs-McLean plant, McLean field, Jefferson County	35.0	6.0	4	....	....	....	....	....	0.8	....	....
Perkins plant, various fields, Cooke County	25.0	18.3	6&7	....	....	....	....	....	127.2	....	....
Southeast Seminole plant and field, Gaines County	2.5	1.3	3	....	....	....	....	....	10.9	....	....
Walnut Bend plant and field, Cooke County	28.0	9.5	2	....	27.9	....	14.5	....	....	11.6	....
Wellman plant and field, Terry County	4.5	0.7	6&7	....	....	....	....	....	10.2	....	....
United Gas Pipe Line Co.—Agua Dulce Dehydration plant and field, Nueces County, 4-6 Ross Peters #2 of the Puentecitas Andres Fernandes	35.0	76.0	5	....	....	....	....	....	5.2	....	....
Block Dehydration plant, Bethany field, Harrison County, Samuel Monday	25.0	2.0	5	....	....	....	....	....	0.8	....	....
Galveston Bay plant and field, Chambers County, Jacob Armstrong A-2	40.0	15.0	5	....	....	....	....	....	18.0	....	....
Willow Springs Dehydration plant and field, Gregg County, Isaac Skillern	25.0	4.0	5	....	....	....	....	....	0.6	....	....
Warren Petroleum Co.—Azalea plant, Midland County, 2-B38-TWP 3S	NR	8.0	3	....	....	....	....	....	29.3	....	....
Breckenridge plant, Stephens County, 22 Lunatic Asylum Lands	NR	5.7	3	....	....	....	....	....	36.4	....	....
Como plant, Hopkins County, Nacogdoches U. A-703	NR	6.1	1	....	0.1	....	....	....	28.6	....	....
Encinal plant, San Patricio County, 18 G. H. Paul Sub. Coleman Fulton	NR	13.9	2	....	....	....	....	....	11.0	....	....
Fannett plant, Jefferson County, W. H. Smith A-198	NR	17.1	2	....	....	....	....	....	4.0	....	*12.8
Fashing plant, Atascosa County, B-144-J Wilkenson	NR	60.6	1	....	12.7	....	....	....	25.1	13.7	....
Gladewater plant, Gregg County, David Ferguson	NR	12.7	7	25.6	64.2	....	....	....	102.2	....	....
Glass plant, Martin County, 10-38-1n T&P RR	NR	0.3	3	....	....	....	....	....	1.3	....	....
GM&A plant, Wise County, P. Nicholas A-654	NR	142.6	1	....	119.0	19.5	35.7	....	287.8	48.2	....
McLean plant, Wheeler County, 33-24	NR	9.8	6	....	....	....	....	....	48.7	....	....
Monahans plant, Ward County, 4-F	NR	35.4	7	....	....	....	....	....	99.5	....	....
Moores Orchard plant, Fort Bend County, German Immigration No. 8	NR	16.5	7	....	....	....	....	....	27.9	....	....
North Port Nueces plant, Orange County, John Stevenson A-169	NR	4.0	7	....	....	....	....	....	4.1	....	....
Sand Hills plant, Crane County, 21-PSL B-21	NR	43.3	1	....	....	....	....	....	102.8	....	....
Shackelford plant, Shackelford County, 522 TE&L	NR	7.5	3	....	....	....	....	....	27.3	....	....
Spear plant, Gregg County, Mary Van Winkle	NR	2.1	4	....	....	....	....	....	13.1	....	*12.8

Company, plant, location	MMcfd Gas capacity	MMcfd Gas throughput	Process method	Production—1,000 gal/day (Average based on the past 12 months) Ethane	Prop.	Isobut.	Normal or unsplit butane	LP-gas mix	Raw NGL mix	Debut. nat. gaso.	Other
Waddell plant, Waddell-Sand Hills fields, Crane County, 25-B 25	NR	71.6	1						317.6		
Worsham plant, Ward County, 56-34 H&TC RR	NR	11.8	7						18.0		
Total	**27,469.1**	**17,136.5**		**4,359.5**	**5,846.7**	**803.8**	**2,368.0**	**689.5**	**13,509.0**	**2,845.7**	**2,566.7**
UTAH											
Chevron USA Inc.—Red Wash plant and field, Uinta County	38.0	9.0	3							2.8	
El Paso Natural Gas Co.—Aneth plant and field, San Juan County, nw4-6-41s-24e	100.0	19.1	1		14.9				74.2		
Gary Operating Co.—Altonah plant and field, Duchesne County, 5-2s-3w	12.5	7.1	3		7.3		5.4			6.1	
Bluebell plant and field, Duchesne County, 23-1s12w	23.0	21.0	2		22.9					38.7	
Koch Oil Co.—Cedar Rim plant and field, Duchesne County, 21-3s-6w	10.0	8.3	3		6.1		5.3			10.9	
Quasar Energy Inc.—Pineview plant and field, Summit County, 3-2n-7e	10.0	4.0	3					6.0			
Shell Oil Co.—Altamont plant, Altamont and Bluebell fields, Duchesne County, 34-1s-4w	40.0	20.0	3		32.0		20.2		41.4		
Union Oil Co. of California—*Lisbon plant and field, San Juan County, 22-30s-24e	80.0	54.4	3		40.2		27.5		14.8		
Total	**313.5**	**142.9**			**123.4**		**58.4**	**6.0**	**130.4**	**58.5**	
WEST VIRGINIA											
Columbia Gas Transmission Corp.—Cobb plant, Central W. Va. field, Kanawha County, Big Sandy	35.0	30.0	2						101.0		
Kenova plant, Southern W. Va. and Eastern Kentucky field, Wayne County, Ceredo district	170.0	113.0	2						223.0		
Consolidated Gas Supply Corp.—Hastings plant, Wetzel County	150.0	90.0	3	175.4	107.6	18.3	34.3			34.5	
Pennzoil Co.—*13 small plants	13.0	9.4	3-4-5						25.0		
Total	**368.0**	**242.4**		**175.4**	**107.6**	**18.3**	**34.3**		**349.0**	**34.5**	
WYOMING											
Amoco Production Co.—*Bairoil plant, Lost Soldier-Wertz field, Sweetwater County, 7-26n-90w	5.0	4.3	3		3.1				13.0		
Beaver Creek plant and field, Fremont County, 10-33n-96w	65.0	51.0	2		13.2		16.0			16.7	
Beaver Creek Phosphoria plant, Beaver Creek field, Fremont County, 10-33n-96w	20.0	8.0	3						8.8		
Elk Basin plant and field, Park County, 29-58n-99w	17.0	10.5	1		9.9		14.6			21.3	
Apexco Inc.—Recluse plant and field, Campbell County, 15-56n-74w	10.0	8.0	3		17.5			18.6			
Atlantic Richfield Co.—Gillette plant, Kitty & Recluse fields, Campbell County, 18-50n-73w	31.0	18.2	3		44.1		23.0			18.9	
Riverton Dome plant and field, Fremont County, 36-1s-4e	30.0	8.9	2						2.0		
Champlin Petroleum Co.—Brady plant* and field, Sweetwater County	65.0	34.0	2							17.1	
Patrick Draw plant* and field, Sweetwater County	30.0	10.0	2		9.1	1.7	2.5			6.2	
Chevron USA Inc.—Birch Creek plant and field, Sublette County	20.0	14.0	5							1.5	
Cities Service Co.—Thunder Creek plant and field, Campbell County, 24-43n-69w	18.0	8.0	7						5.7		
Colorado Interstate Gas Co.—Rawlins plant, Carbon County, sw4-sw4-25-21n-86w	220.0	203.0	2		65.5		36.4		13.7		
Colorado Oil Co. Inc.—Patrick Draw plant and field, Sweetwater County	10.0	6.0	2		4.0		2.0			4.0	
Continental Oil Co.—Sussex plant and field, Johnson County, 243-41n-78w	15.0	2.3	3		2.8				3.2		
CRA Inc.—Joe Creek plant, Campbell County	2.0	0.3	3						2.4		
Lazy B plant, Campbell County	5.0	2.8	3		4.4			4.5			
Ginther Gas Processing Plants—Rozet plant and field, Campbell County, 18-50n-69w	4.0	0.2	2		0.9						[11]1.5
Springen plant, Springen Ranch field, Campbell County, 28-51n-71w	8.0	1.0	2		3.4						[11]5.6
Husky Oil Co.—Ralston plant, various fields, Park County, sw¼-3-56n-101w6	7.0	3.0	3		0.3		0.9			1.4	
Kansas-Nebraska Natural Gas Co. Inc.—Casper plant, main line field, Natrona County, 10-33n-65w	80.0	44.0	2		19.0		11.2			8.7	
Flat Top plant, Flat Top and other fields, Converse County, 20-33-68	8.0	2.3	2		3.4				3.2		

APPENDIX B

LIST OF CONVERSION FACTORS
ENGLISH - SI METRIC SYSTEM

LIST OF CONVERSION FACTORS

To Convert From	Multiply By	To Get
Cubic Feet	0.0283	Cubic Meter
Short Ton, t	0.907	Metric Ton, T
Barrel (petroleum, 42 gal)	0.159	Cubic Meter
Gallon	0.00378	Cubic Meter
ppm SO_2	0.350	mg/m^3 SO_2
ppm H_2S	0.186	mg/m^3 H_2S
pounds-per-square inch, psi	6895.	Pascals, Pa

APPENDIX C

MAJOR DOMESTIC GAS SUPPLY COMPANIES, 1975(8)

Table 25 - MAJOR GAS SUPPLY COMPANIES

Annual Gross Change In Reserves, Annual Production and Gross Change-Production (GC/P) Ratios 1/
12-31-70 to 12-31-75
(All Volumes in Thousands Mcf at 14.73 Psia @ 60°F.)

Company	Item	Year End 1970	Annual Gross Change In Reserves 2/ Increase or (Decrease) 1971	1972	1973	1974	1975	Year End 1975	Total Change 12-31-70 to 12-31-75
Arkansas Louisiana Gas Co.	Reserves	6,619,466	(218,950)	161,335	(181,276)	26,951	79,204	4,594,344	(132,736)
	Annual Production	496,350	431,951	407,515	405,981	331,051	315,888	315,888	1,892,386
	GC/P Ratio		(0.50)	0.40	(0.44)	0.08	0.25		(0.07)
Cities Service Gas Co.	Reserves	6,072,876	76,221	111,489	174,245	(47,224)	317,544	4,502,432	632,275
	Annual Production	492,981	493,461	487,177	462,220	401,820	358,041	358,041	2,202,719
	GC/P Ratio		0.15	0.23	0.38	0.12	0.89		0.29
Colorado Interstate Gas Co.	Reserves	4,786,359	198,296	21,304	(78,418)	237,397	546,012	3,818,219	924,591
	Annual Production	365,543	353,564	361,472	409,654	384,318	383,713	383,713	1,892,731
	GC/P Ratio		0.56	0.06	(0.19)	0.62	1.42		0.49
Columbia Gas Transmission Corp.	Reserves	9,104,479	728,737	(832,317)	235,589	(253,256)	(353,172)	4,642,660	(474,419)
	Annual Production	794,190	839,510	878,895	860,401	792,489	616,105	616,105	3,987,400
	GC/P Ratio		0.87	(0.95)	0.27	0.32	(0.57)		(0.12)
Consolidated Gas Supply Corp.	Reserves	1,033,953	203,183	57,802	165,761	140,487	44,146	1,114,056	611,379
	Annual Production	117,811	107,426	101,248	109,618	109,209	103,775	103,775	531,276
	GC/P Ratio		1.89	0.57	1.51	1.29	0.43		1.15
El Paso Natural Gas Co.	Reserves	26,746,900	142,800	(25,800)	(200,711)	(4,817,872)	130,274	14,511,393	(4,771,309)
	Annual Production	1,666,700	1,703,600	1,688,800	1,533,799	1,314,633	1,223,366	1,223,366	7,464,198
	GC/P Ratio		0.08	(0.02)	(0.13)	3.66	0.11		(0.64)
Florida Gas Transmission Co.	Reserves	1,421,059	131,349	(93,728	(11,782)	(119,776)	66,005	865,776	(27,932)
	Annual Production	136,479	115,157	114,953	119,242	102,166	75,833	75,833	527,351
	GC/P Ratio		1.14	(0.82)	(0.10)	(1.17)	0.87		(0.05)
Kansas-Nebraska Natural Gas Co., Inc.	Reserves	2,475,162	(39,264)	(52,127)	8,631	(1,628)	41,630	1,826,854	(42,758)
	Annual Production	167,531	126,338	121,281	115,075	123,347	119,509	119,509	605,550
	GC/P Ratio		(0.31)	(0.43)	0.07	0.01	0.35)		(0.07)
Michigan Wisconsin Pipe Line Co.	Reserves	8,353,799	162,462	716,251	364,072	(263,703)	(76,392)	5,828,603	902,690
	Annual Production	601,603	636,082	678,60[illegible]	713,671	711,218	688,311	688,311	3,427,886
	GC/P Ratio		0.26	1.06	0.61	0.37	(0.11)		0.26

Table 25 - MAJOR GAS SUPPLY COMPANIES

Annual Gross Change In Reserves, Annual Production and Gross Change-Production (GC/P) Ratios 1/
12-31-70 to 12-31-75
(All Volumes in Thousands Mcf at 14.73 Psia @ 60°F.)

		Year End 1970	Annual Gross Change in Reserves 2/ Increase or (Decrease)					Year End 1975	Total Change 12-31-70 to 12-31-75
			1971	1972	1973	1974	1975		
Montana-Dakota Utilities Co.	Reserves	916,449	29,343	15,202	93,954	56,657	(14,458)	822,718	180,698
	Annual Production	63,016	58,264	55,811	55,838	53,072	51,444	51,444	274,429
	GC/P Ratio		0.50	0.27	1.68	1.07	(0.28)		0.66
Mountain Fuel Supply Co.	Reserves	1,465,935	58,298	155,622	83,789	49,008	85,065	1,410,680	431,782
	Annual Production	93,287	95,129	94,098	99,578	97,713	100,519	100,519	487,037
	GC/P Ratio		0.61	1.65	0.84	0.50	0.85		0.89
Natural Gas Pipeline Co, of America	Reserves	10,575,947	264,395	124,780	161,613	476,765	(139,277)	6,973,891	888,276
	Annual Production	988,384	961,834	923,390	879,868	844,835	880,405	880,405	4,490,332
	GC/P Ratio		0.27	0.14	(0.18)	0.56	(0.16)		0.20
Northern Natural Gas Co.	Reserves	13,748,646	778,918	315,283	(614,121)	(99,6[illegible])	(393,398)	9,125,981	(12,951)
	Annual Production	899,734	907,108	928,633	949,810	918,252	905,911	905,911	4,609,714
	GC/P Ratio		0.86	0.34	(0.65)	0.11	(0.43)		0.00
Northwest Pipeline Corp. (First Form 15 filed for year 1974)	Reserves					4,661,581	(17,275)	4,349,264	4,644,306
	Annual Production					147,507	147,535	147,535	295,042
	GC/P Ratio						(0.12)		15.7
Panhandle Eastern Pipe Line Co.	Reserves	6,542,927	(17,384)	(9,657)	175,816	765,975	316,971	4,874,939	1,231,721
	Annual Production	553,378	586,469	594,061	592,761	586,258	540,160	540,160	2,899,709
	GC/P Ratio		(0.03)	0.02	0.30	1.31	0.59		0.42
Sea Robin Pipeline Co.	Reserves	948,109	(174,038)	762,190	120,873	127	35,641	751,205	744,793
	Annual Production	4,774	77,431	96,811	206,206	270,863	290,976	290,976	942,287
	GC/P Ratio		(2.31)	7.87	0.59	0.00	0.12		0.79
South Texas Natural Gas Gathering Co.	Reserves	88,109	(402,389)	106,760	36,743	(43,527)	(100,986)	291,953	(403,399)
	Annual Production	67,870	73,308	63,037	60,286	52,268	43,858	43,858	292,757
	GC/P Ratio		(5.49)	1.69	0.61	0.83	(2.30)		(1.38)
Southern Natural Gas Co.	Reserves	5,979,871	54,845	74,569	(31,596)	362,167	82,922	3,199,104	(181,427)
	Annual Production	593,684	574,727	601,355	507,789	472,977	442,492	442,492	2,599,340
	GC/P Ratio		0.10	0.12	(0.06)	(0.77)	0.19		(0.07)
Tennessee Gas Pipeline Co. (Division of Tenneco)	Reserves	18,188,079	741,131	(838,072)	385,003	(1,206,793)	(785,339)	9,877,315	(1,704,070)
	Annual Production	1,380,693	1,346,791	1,348,646	1,327,130	1,273,023	1,211,104	1,211,104	6,506,694
	GC/P Ratio		0.55	(0.62)	0.29	0.95	(0.65)		(0.26)

Table 25 - MAJOR GAS SUPPLY COMPANIES

Annual Gross Change In Reserves, Annual Production and Gross Change-Production (GC/P) Ratios 1/
12-31-70 to 12-31-75
(All Volumes in Thousands Mcf at 14.73 Psia @ 60°F.)

Company	Item	1970	Annual Gross Change in Reserves 2/ Increase or (Decrease) 1971	1972	1973	1974	1975	Year End 1975	Total Change 12-31-70 to 12-31-75
Texas Eastern Transmission Corp.	Reserves	7,509,265	(385,847)	239,377	28,541	(84,136)	(60,734)	4,548,306	(262,799)
	Annual Production	618,869	620,179	613,491	544,477	486,033	433,980	433,980	2,698,160
	GC/P Ratio		(0.62)	0.39	0.05	0.17	(0.14)		(0.10)
Texas Gas Transmission Corp.	Reserves	6,298,792	151,883	67,580	(59,941)	(7,322)	29,727	3,594,890	181,927
	Annual Production	547,421	591,913	616,031	601,348	567,169	509,368	509,368	2,885,829
	GC/P Ratio		0.26	(0.11)	0.10	0.01	0.06		0.06
Transcontinental Gas Pipe Line Corp.	Reserves	9,826,855	(753,610)	(205,589)	654,489	(75,959)	(380,373)	4,673,536	(761,042)
	Annual Production	944,222	987,378	988,430	913,263	799,210	703,996	703,996	4,392,277
	GC/P Ratio		(0.76)	(0.21)	0.72	(0.10)	(0.54)		(0.17)
Transwestern Pipeline Co.	Reserves	4,335,284	11,626	(235,853)	(63,217)	(290,569)	(144,593)	1,862,188	(722,606)
	Annual Production	335,989	350,159	365,952	381,800	345,035	307,544	307,544	1,750,490
	GC/P Ratio		0.03	(0.64)	(0.17)	0.84	(0.47		(0.41)
Trunkline Gas Co.	Reserves	5,575,924	171,769	6,554	(239,587)	(316,252)	(805,512)	2,161,546	(1,183,028)
	Annual Production	468,552	511,111	522,234	448,655	385,002	364,348	364,348	2,231,350
	GC/P Ratio		0.34	0.01	(0.53)	0.82	(2.21)		(0.53)
United Gas Pipe Line Co.	Reserves	10,316,117	(3,590)	(539,253)	(433,842)	(272,485)	(67,428)	3,855,435	(1,316,598)
	Annual Production	1,373,081	1,295,149	1,178,111	1,032,315	861,102	777,407	777,407	5,144,084
	GC/P Ratio		(0.003)	(0.46)	(0.42)	0.32	(0.09)		(0.26)
West Texas Gathering Co.	Reserves	838,594	10	(47,594)	(12,783)	(21,992)	(42,212)	249,895	(124,571)
	Annual Production	88,228	94,029	93,124	94,736	92,612	89,627	89,627	464,128
	GC/P Ratio		0.00	(0.51)	(0.13)	0.24	(0.47)		(0.27)
Total	Reserves	170,669,546	1,910,194	56,108	761,845	(1,869,346)	(1,612,308)	104,427,183	(747,207)
	Annual Production	13,855,593	13,938,068	13,923,160	13,425,531	12,523,182	11,685,215	11,685,215	65,495,156
	GC/P Ratio		0.13	0.004	0.05	0.15	(0.14)		(0.01)
Totals Adjusted to Eliminate Duplications Between Major Companies and to Correct Arithmetic Errors in Reported Data.									
	Reserves	169,972,688	2,012,899	52,985	1,027,694	(841,802)	(1,808,837)	104,773,499	442,939
	Annual Production	13,790,840	13,914,403	13,891,093	13,402,126	12,706,198	11,728,308	11,728,308	65,642,123
	GC/P Ratio		0.14	0.004	0.08	0.07	(0.15)		

1/ Excludes pipeline imports, LNG and SNG.
2/ Gross change in reserves is the net change in reserves plus annual production.

APPENDIX D

ACID GAS REMOVAL PROCESSES USED IN THE NATURAL GAS PROCESSING INDUSTRY

AMINE PROCESSES

Monoethanolamine (MEA) --

This first amine solution is composed of 10-20 wt % MEA in water. This alkaline compound is the strongest base of the three common amines. It reacts most rapidly with the acid gases and removes both H_2S and CO_2. MEA has the lowest molecular weight of the common amines, so it has a greater carrying capacity for acid gases on a unit weight or volume basis. This means that less solution circulation is necessary to remove a given amount of acid gases. MEA is chemically stable which minimizes solution degradation. However, it reacts irreversibly with COS and CS_2 which results in solution loss and buildup of reaction products in the MEA solution. Also, it has a higher vapor pressure than the other amines. This can result in significant solution losses through vaporization although this handicap can usually be overcome by a simple water wash of the sweetened gas stream. This is the most commonly used acid-gas removal process.

The advantages of MEA are high reactivity, low solvent cost, good chemical stability, ease of reclamation, high selectivity for acid gases, and lower plant investment. The disadvantages are irreversible degradation by COS, CS_2 and O_2 in the gas, high vaporization losses, ineffectiveness in removing mercaptans, nonselectivity for H_2S in the presence of CO_2, and high utility costs. The general guidelines for use are for gases containing up to 1.4 g/m^3 (4 grains H_2S/100 scf) to 15 mol % total acid gas, with acid gas partial pressures up to .69 MPa (100 psia).

Diethanolamine (DEA) --

This amine solution is comprised of 20-30 wt % DEA in water. It is similar to MEA but reacts very slowly with COS and CS_2 making it more useful where these compounds are prevalent. It is also less volatile than MEA so there are lower losses of amine solution due to vaporization. The disadvantages of DEA are lower reactivity, higher solvent circulation rates, and higher solvent cost.

Triethanolamine (TEA) --

TEA is less reactive with acid gases and has less acid gas carrying capacity per volume of solution than either MEA or DEA. It is unable to reduce H_2S content to general pipeline specifications but has the advantage of high selectivity for H_2S.

Methyldiethanolamine --

This amine is not commercially competitive with MEA and DEA, but it may have some value in special applications.

Glycol-Amine --

The glycol-amine process utilizes MEA (or occasionally DEA) in combination with a glycol to simultaneously sweeten and dehydrate the gas stream. Typical solutions consist of 10-30% MEA, 45-85% glycol, and 5-25% water by weight. The combined process costs less than separate MEA and glycol units. However, it has the disadvantages of high MEA vaporization losses due to high regeneration temperature, intricate corrosion problems, and reclaiming must be by vacuum distillation. Its best application is for gas streams not requiring low water dewpoint control.

Fluor Econamine or Diglycolamine (DGA) --

The treating agent used in this process patented by Fluor is an aqueous solution of the primary alkanolamine HO-C_2H_4-HN_2, tradename Diglycolamine. It is also known as 2(2-amino-ethoxy) ethanol. There are several advantages of this process over MEA. It can be used in concentrations of 50-80% which results in approximately twice as much acid gas pickup per gallon as an MEA solution in the 15-20% range. The freezing point of DGA is 233°K (-40°F), thus it is good for cold weather areas. It removes COS and mercaptans as well as CO_2 and H_2S and has lower vaporization losses than MEA. It is in use at about 15 plants in the U.S.

Sulfinol --

The Sulfinol process, patented by Shell, is based on the use of an organic solvent, sulfolane (tetrahydrothiophene dioxide) mixed with an alkanolamine (di-isopropyl-amine or DIPA), and water. This is a unique process that involves simultaneous physical and chemical absorption through a physical solvent and a chemically reactive agent. A typical solvent is composed of 40-50% sulfolane, 40-45% DIPA, and 10-20% water. This process is equivalent to MEA at lower partial pressures but it is superior at higher partial pressures with an extremely high affinity for the sour components. Sulfinol can also absorb more hydrocarbons than its MEA equivalent as well as removing COS, CS_2, thiols, and mercaptans. Its best application is for gas streams with relatively high ratios of H_2S (H_2S to CO_2 ratios 1:1 or greater) and when acid-gas partial pressures exceed 0.75 MPA (110 psia). Sulfinol is used primarily on so-called "dry gases," i.e., when there is very little C_5+ or even much C_3 and C_4 present. DEA is used when treating the hydrocarbon rich gases (high content of C_5+). It is the second most widely used acid gas removal process. This process is in use at about 40 plants in the U.S.

SNPA-DEA --

This process is similar to the conventional amine process but utilizes a higher weight percent of DEA (25-30%) than the conventional DEA process (20-25%). It is used for sweetening raw gas streams containing a total of about 10% or more of acid gases at operating pressures of about 3.4 MPa (500 psia) or higher. Unlike MEA units, COS is removed without degradation of the DEA solutions. The main differences with a conventional DEA process, aside from the higher DEA concentrations, are the optimization of operating conditions to achieve higher than conventional loading of the rich DEA in terms of cubic meters of gas per cubic meter of solution (SCF per gallon). A slipstream of a lean solution is conditioned to maintain low level of solids, corrosion products, and hydrocarbons.

Adip --

The last amine process used for sweetening is the Adip process licensed by Shell. The process is based on an absorption-regeneration cycle using a circulating aqueous solution of an alkanolamine (DIPA) which reacts with acidic gases. The Adip process has a low steam consumption rate which is economically beneficial. It is very selective for H_2S in the presence of CO_2 and substantial H_2S removal is realized to less than 26 mg/m^3 (10 ppm) with partial removal of COS, CO_2 and mercaptans.

CARBONATE PROCESSES

A flow diagram of a typical carbonate process is presented in Figure D-1. The basic concept is that the CO_2 reacts with potassium carbonate to form bi-carbonate which decomposes at elevated, temperatures. A similar reaction takes place with H_2S. Various additives, frequently arsenates, accelerate H_2S removal by forming thioarsenates which decompose into arsenates and elemental sulfur. Some additives assist the rate of gas absorption by accelerating the hydration of CO_2 gas. CO_2 has a high affinity for potassium carbonate with H_2S having a lesser affinity. The reactions are as follows:

$$K_2CO_3 + H_2O \rightleftarrows 2KHCO_3$$

$$K_2CO_3 + H_2S \rightleftarrows KHS + KHCO_3$$

High temperatures are employed to keep the salt in solution. The process won't work if there is only H_2S present and no CO_2 since potassium bisulfide is difficult to regenerate in the absence of CO_2.

The advantage of the carbonate process is that COS and CS_2 can be removed without significant solution degradation. The disadvantages are the highly corrosive nature of the absorbents and absorbent-acid compounds and the difficulty in removing H_2S to pipeline specifications. An amine process clean-up is frequently needed.

The following paragraphs describe seven processes that are used or have been used for acid gas sweetening in this manner.

Hot Potassium Carbonate (Uncatalyzed) --

In this form the carbonate process, the absorber and regenerator both operate at elevated temperatures in the neighborhood of 380-390°K (230-240°F). The higher temperatures increase the solubility of the potassium bicarbonate in solution, permitting the use of the concentrated K_2CO_3 solution, which increases its carrying capacity for acid gases. Since this process runs at a much higher temperature than an amine process, savings are realized in heat exchange and heating equipment. This process is very effective where 5 to 8 mol % acid gases are present in large quantities at contactor pressures of 2.1 MPa (300 psia). The solution is typically 15 to 30 wt % potassium carbonate in water.

Catacarb Process --

The Catacarb process is a variation of the hot potassium carbonate process in which amine borates are used to increase the activity of the hot potassium carbonate solution. This solution is not highly ionized and has few hydroxyl ions which can react directly with CO_2. The Catacarb process is based on the

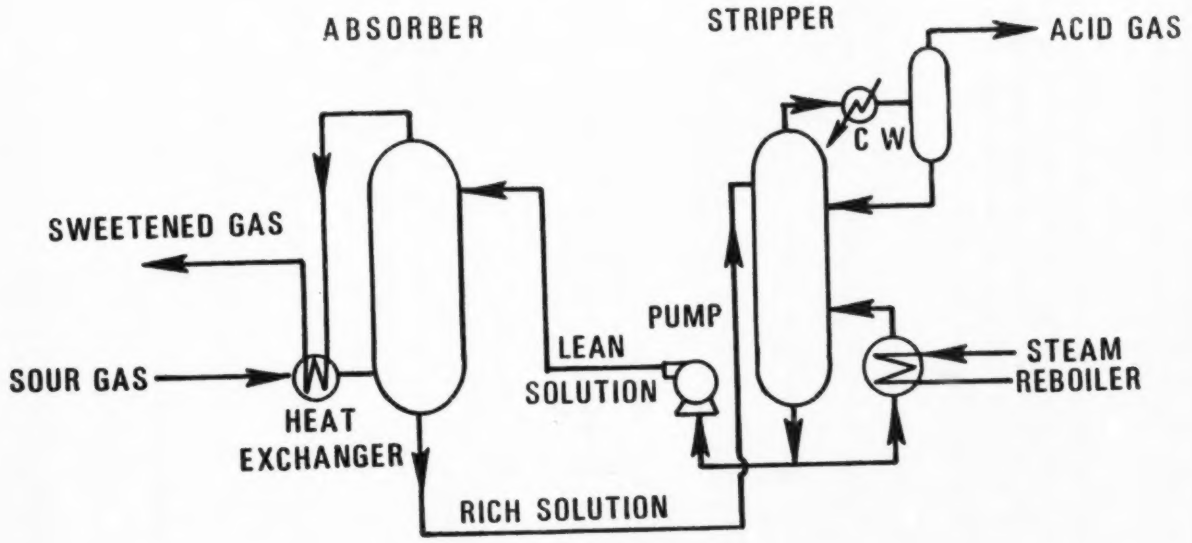

ABSORBER
STRIPPER
ACID GAS
C W
SWEETENED GAS
PUMP
LEAN
SOLUTION
STEAM
REBOILER
SOUR GAS
HEAT
EXCHANGER
RICH SOLUTION

Figure D-1: Flow diagram of conventional hot carbonate process.(9)

fact that CO_2 must first react with water or a hydrate to form carbonic acid. Next, the carbonic acid reacts with a carbonate ion to form two bicarbonate ions.

The process also frequently contains corrosion inhibitors. The solutions frequently become contaminated by potassium formate and potassium sulfate. These contaminants have a negative effect on solution activity. They can be removed or maintained at a satisfactory level in the solution, but to do so is expensive and results in potassium carbonate losses.

Benfield Process --

The Benfield process is another version of the hot potassium carbonate process which uses diethanolamine as the activation agent to improve the treating capabilities of the solution. The flow and operating conditions are essentially the same as those for the hot potassium carbonate process. It can be used for gases containing up to 75% CO_2 and H_2S.

DEA Carbonate --

This process is a combination of the DEA and hot potassium carbonate processes. Gas entering the absorber first contacts an activated potassium carbonate solution. It then flows to the upper section where it is treated with the DEA solution. This enables a more complete removal of the acid gases. The solutions are segregated in both the absorber and regenerator. The spent DEA from the absorber is preheated by the carbonate solution before it is introduced to the lower section of the regenerator and both sections are reboiled before entering the regenerator.

The DEA-Carbonate process requires a high percentage of CO_2 to operate effectively. An advantage is that it can save as much as 10% in operation costs over the DEA process alone in certain applications.

Giammarco-Vetrocoke (GV) Process --

The GV process is used for the continuous removal of H_2S by scrubbing the sour gas with alkali arsenates and arsenite solutions, thus producing sulfur as a direct precipitate. Sodium carbonate is the alkali usually applied since it is relatively inexpensive. CO_2 is also removed since the catalyst increases the rate of absorption of CO_2 in alkali carbonate solutions.

There are many reasons for choosing this process:

- Treating costs are about one-half the costs of most other processes.
- Low capital costs.
- Low corrosivity.
- No solution degradation.
- The treated gas has a low H_2S content.

- The process can operate at pressures as low as atmospheric and temperatures up to 420°K (300°F).

However, the use of this process in the U.S. is extremely limited due to the high toxicity of the arsenic used in the absorption solution.

Seaboard Process --

This process was developed by the Koppers Co. in 1920 and is no longer of major industrial significance. It is a regenerative process without recovery of the product removed. An aqueous solution of 3-3.5% sodium carbonate is used for absorbing H_2S in a bubble tray or packed tower. The foul solution is pumped to a second tower where it is regenerated by aeration to release the absorber H_2S to the atmosphere.

Vacuum Carbonate Process --

The vacuum carbonate process is a modification of the Seaboard process which also uses 3-3.5% sodium carbonate as an absorbent. It was especially adapted to recovery of H_2S from manufactured gases and is used for treating coke-oven gases.

PHYSICAL ABSORPTION PROCESSES

These methods use organic solvents and accomplish the acid-gas removal mainly by physical absorption, rather than chemical reaction, which is directly proportional to the acid-gas partial pressure in the sour-gas stream. A physical process should be considered under the following conditions:

- The partial pressure of the acid gas in the feed is 0.34 MPa (50 psig) or higher.
- The concentration of heavy hydrocarbons in the feed gas is low.
- Only bulk removal of the acid gas is desired.
- The solvent is able to do satisfactory dehydration as well as acid gas removal.
- Selective H_2S removal is desired.

If heavy hydrocarbons are present in any great quantity, problems will arise with the physical processes. All of the physical solvents used have a relatively high solubility for the heavy hydrocarbons. This is especially true of the aromatic and unsaturated hydrocarbons. If these are present and care is not taken in the regeneration cycle, then the acid gases will be rendered unsuitable for feed gas to a sulfur recovery unit. Another disadvantage is the high solvent costs.

Water Absorption --

The water absorption process is simply the washing of the acid gas stream with water which acts as a solvent for the acid gases. A flow diagram of this process is presented in Figure D-2. It is a good process to use as a companion to an amine process. A water wash followed by an amine process clean-up requires 12-14% lower investment. Additionally, there is an approximate 50% savings in operational costs of an equivalent amine unit designed to do the total job.

Fluor Solvent Process --

The Fluor Solvent Process employs an anhydrous organic compound to remove CO_2 and H_2S from natural gas streams. The compound can be one of four: propylene carbonate, glycerol triacetate, butoxyl diethylene glycol acetate, or methoxy-triethylene glycol acetate. Propylene carbonate is the most common one in use today. The use of the high capacity solvent, which absorbs acid gas by dissolution, permits solvent regeneration simply by pressure letdown of the rich solvent, usually without the application of heat. Other advantages are low solvent loss due to the low vapor pressure of propylene carbonate and a virtually zero solvent breakdown rate. The process is favored when there are high concentrations of CO_2 and H_2S and when their combined partial pressure is 0.52 MPa (75 psia) or higher. In addition, the use of this process is favored for raw gas with low heavy hydrocarbon content.

A flow diagram of this process is presented in Figure D-3.

Selexol Process --

The Selexol Process is used for gas purification removal of H_2S, CO_2, COS, mercaptans, etc., from gas streams. The solvent, dimethylether or polyethylene glycol, is trade named Selexol by Allied Chemical Corp. It has a strong preference for sulfur-based compounds, while retaining the capability to absorb bulk quantities of all impurities economically. It is also capable of simultaneously dehydrating gas to pipe line specfications. Its advantages are lower initial plant cost and lower operating costs than MEA or potassium carbonate, more selectivity for H_2S than MEA, and better ability to remove for H_2S than hot potassium carbonate. It is primarily used on high CO_2 content streams (18-43 mol %) with low H_2S (<1 mol %). This process is not effective for low acid-gas partial pressures.

A flow diagram of this process is presented in Figure D-4.

Rectisol Process --

This process which uses methanol as a solvent, was developed by the German Lurgi Co. Because of the vapor pressure of methanol, the process is normally applied at extremely low temperatures, i.e., 200-240°K (-30 to -100°F). It is used primarily for synthesis gas, but has been applied for purification of natural gas for LNG production. The process is best suited where there are limited quantities of ethane and heavier components. Ammonia evaporation and cold, purified gas are used to cool the feed gas to the desired temperature.

A flow diagram is presented in Figure D-5

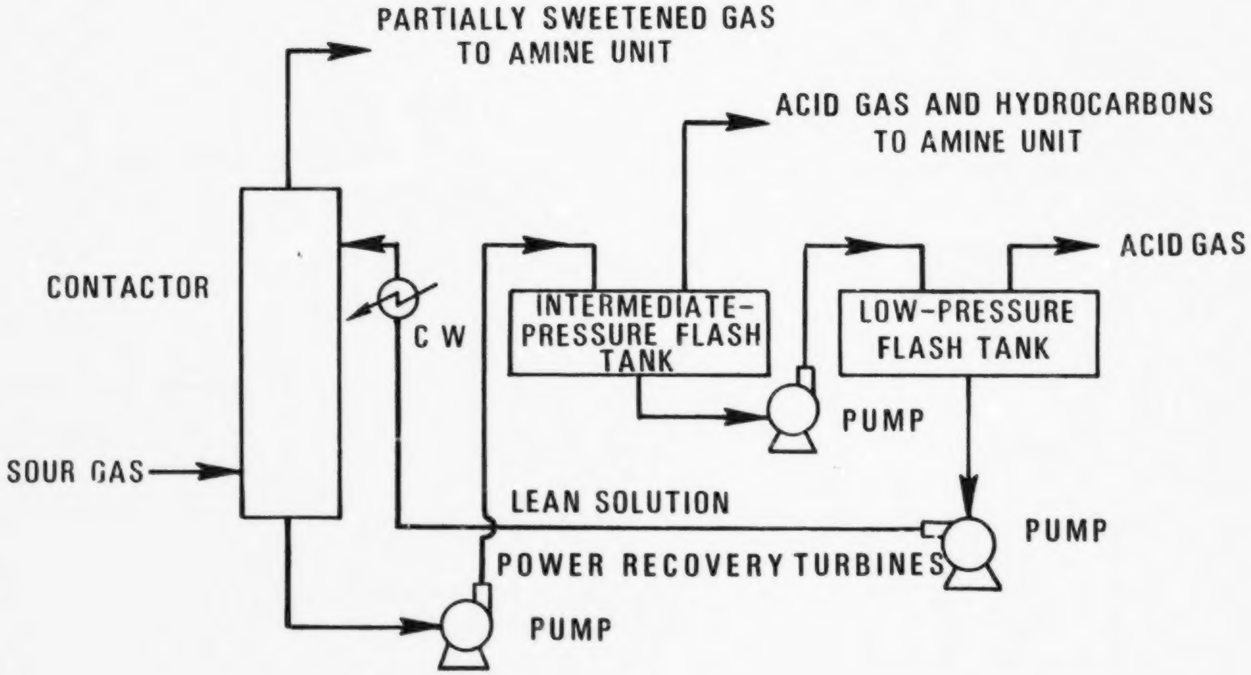

PARTIALLY SWEETENED GAS
TO AMINE UNIT
ACID GAS AND HYDROCARBONS
TO AMINE UNIT
ACID GAS
CONTACTOR
C W
INTERMEDIATE-
PRESSURE FLASH
TANK
LOW-PRESSURE
FLASH TANK
PUMP
SOUR GAS
LEAN SOLUTION
PUMP
POWER RECOVERY TURBINES
PUMP

Figure D-2: Flow diagram of a typical water wash absorption unit.(9)

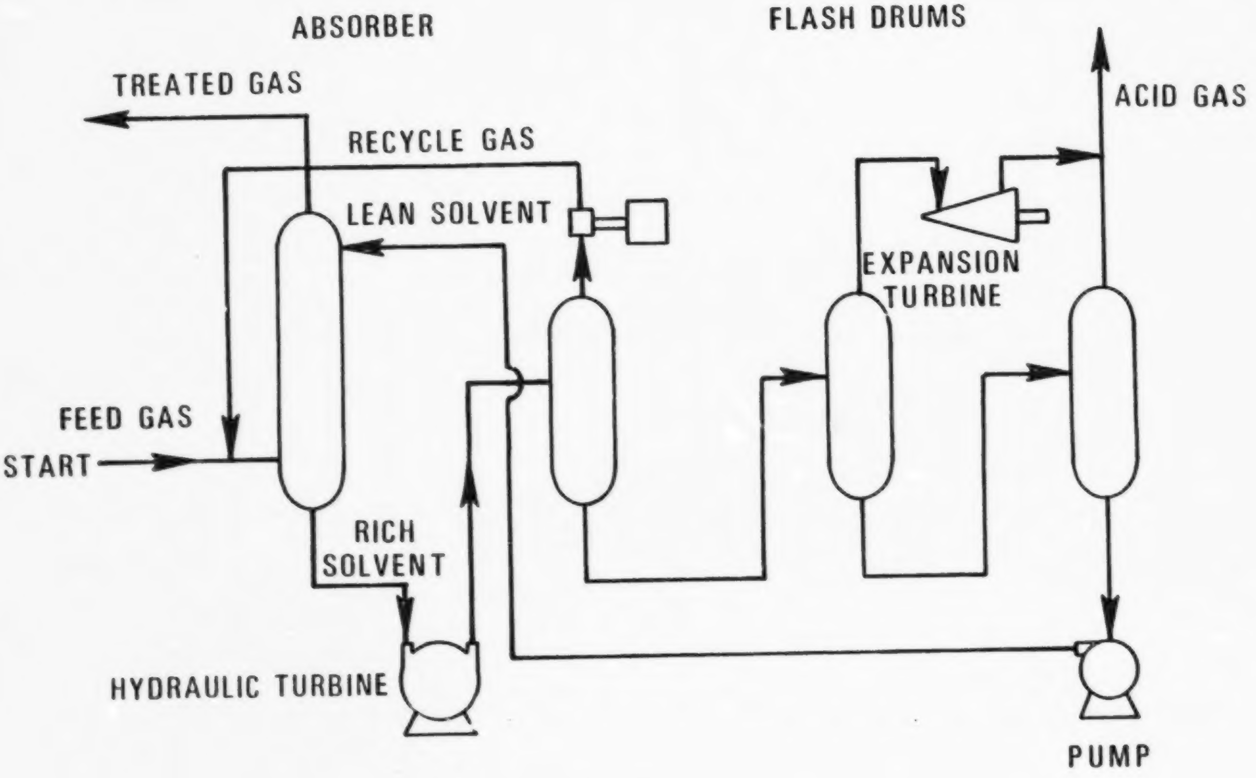

ABSORBER
FLASH DRUMS
TREATED GAS
RECYCLE GAS
LEAN SOLVENT
ACID GAS
EXPANSION TURBINE
FEED GAS
START
RICH SOLVENT
HYDRAULIC TURBINE
PUMP

Figure D-3: Flow diagram of Fluor solvent process.(13)

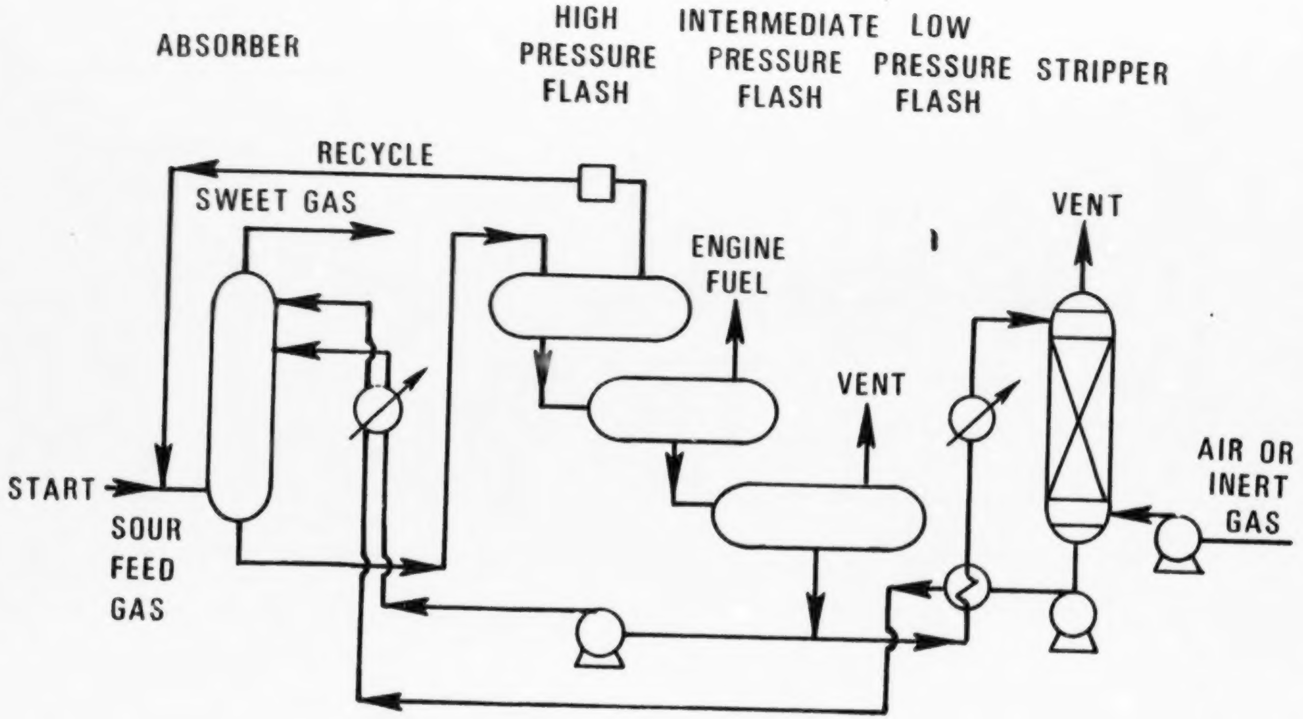

ABSORBER
HIGH PRESSURE FLASH
INTERMEDIATE PRESSURE FLASH
LOW PRESSURE FLASH
STRIPPER
RECYCLE
SWEET GAS
ENGINE FUEL
VENT
VENT
START
SOUR FEED GAS
AIR OR INERT GAS

Figure D-4: Flow diagram of Selexol process.(13)

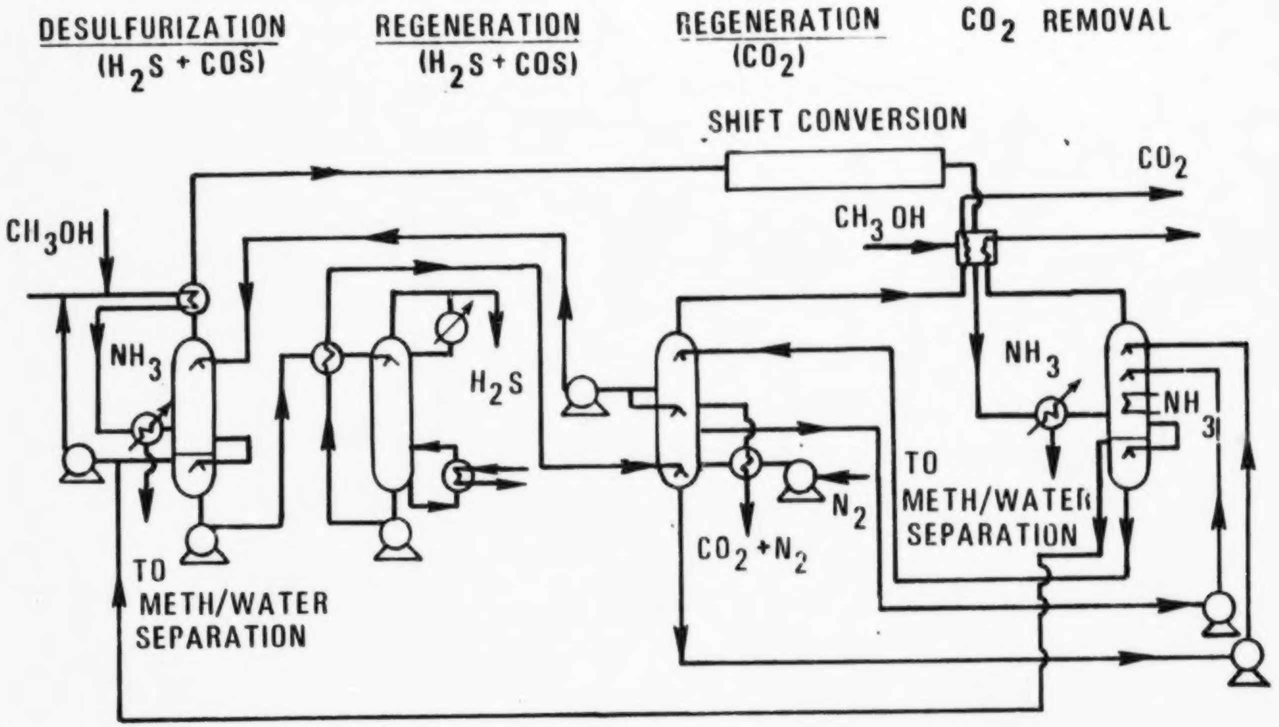

DESULFURIZATION
(H_2S + COS)
REGENERATION
(H_2S + COS)
REGENERATION
(CO_2)
CO_2 REMOVAL
SHIFT CONVERSION
CO_2
CH_3OH
CH_3OH
NH_3
H_2S
NH_3
NH_3
TO
METH/WATER
SEPARATION
N_2
CO_2 + N_2
TO
METH/WATER
SEPARATION

Figure D-5: Flow diagram of the Rectisol process.(13)

Purisol Process --

The Purisol Process, also developed by Lurgi, uses an absorbing solution of N-methyl-pyrrolidone (NMP) for removing acid gases from synthetic and natural gas streams. The process is highly selective for H_2S. Other advantages include low temperature operation (ambient), CO_2 removal by pressure letdown, excellent solvent stability, and nontoxic, fumeless operation.

A flow diagram is presented in Figure D-6.

Estasolven Process --

This is a process that utilizes the solvent tri-n-butyl phosphate (TBP) for either sweetening only or sweetening combined with liquid hydrocarbon recovery. In addition to removing H_2S, TBP will remove mercaptans and other organic sulfur compounds.

Other Solvents --

Various other physical solvents can be used in natural gas sweetening. Possible solvents include: methyl cyanoacetate, glutaronitrile, trimethylene cyanohydrin, dimethyl formamide, and DEG dimethyl ether. Any of these may be applicable depending upon plant design and the nature of the gas to be sweetened.

SOLID BED SWEETENING PROCESSES

Solid bed sweetening processes are all based on the adsorption of the acid gases on the surface of the solid sweetening agent or on the reaction with some component on that surface. These processes are best applied to gases containing low to medium concentrations of H_2S or mercaptans, but are not widely used. They do not usually remove significant quantities of CO_2. An advantage is that pressure has little effect on the adsorptive capacity of the sweetening agent.

Iron Sponge --

The iron sponge process, also known as the iron oxide or dry box process, was introduced in England in the mid-19th century. The process involves contact of the sour gas with wood chips impregnated with ferric oxide in hydrated form. Ferric sulfide is formed which oxidizes to sulfur and ferric oxide when exposed to air. The ferric oxide can then react with additional H_2S. The process is as follows:

$$2Fe_2O_3 + 6H_2S \rightarrow 2Fe_2S_3 + 6H_2O$$

$$2Fe_2S_3 + 3O_2 \rightarrow 2Fe_2O_3 + 6S$$

This is repeated several times until the sulfur covers most of the surface of the oxide particles.

The reasons for the choice of this process are:

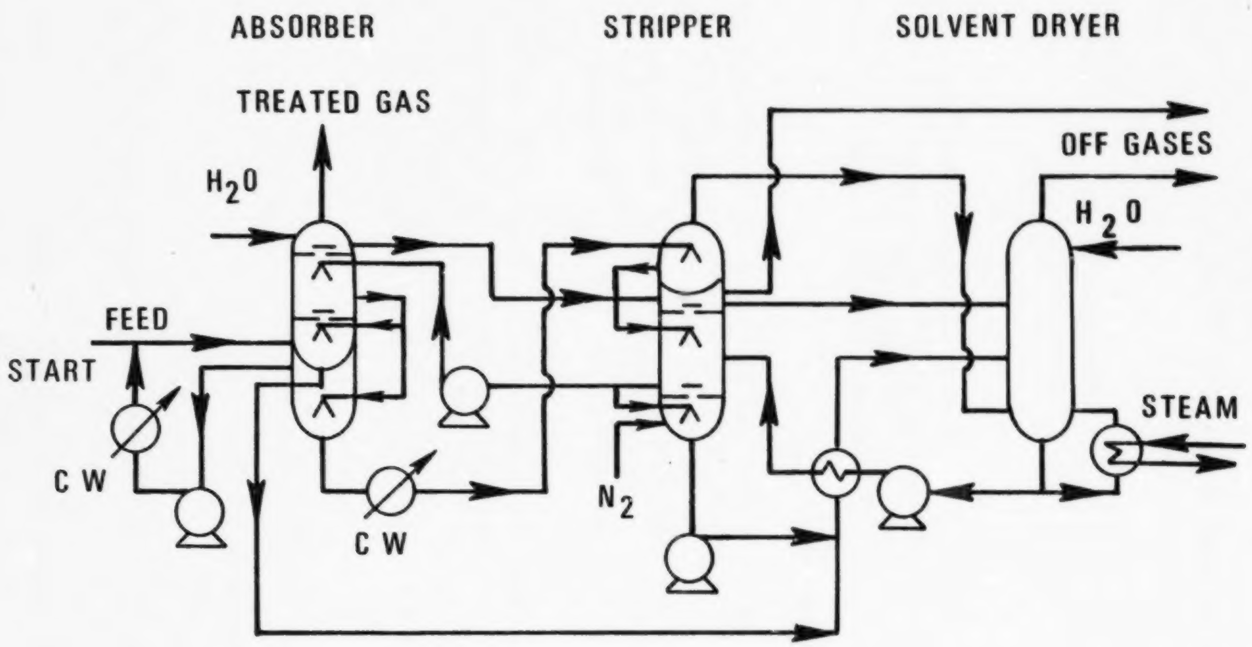

ABSORBER
STRIPPER
SOLVENT DRYER
TREATED GAS
OFF GASES
H_2O
H_2O
FEED
START
C W
C W
N_2
STEAM

Figure D-6: Flow diagram of the Purisol process.(13)

- Efficiently removes trace amounts of H_2S in the gas.
- Batch process has low capital and operating cost.
- H_2S removal is independent of gas pressure.
- Easy installation.

The disadvantage is that the removed sulfur is wasted - it cannot be recovered economically. The used iron oxide becomes a solid waste problem. It is also limited to gas streams with low H_2S content <0.36 kgH_2S/m^3 (1000 grains/100 scf) due to the economics of bed replacement.

A flow diagram of the iron sponge process is presented in Figure D-7.

Molecular Sieve --

The molecular sieve process is used in dehydrate and removes CO_2, H_2S, and sulfur compounds from natural gas. Crystalline sodium-calcium-alumino silicates are used. This material is porous, with the pore openings all the same size, and is formed by driving off the water of crystallization that is present during the material synthesis process. The large surface area and highly localized polar charges are the reasons for the very strong adsorption of polar or polarizable compounds on molecular sieves. This results in much higher adsorptive capacities for these materials by the sieves than by other adsorbents particularly in the lower concentration ranges. However, there is a problem with COS formulation which irreversible contaminates the molecular sieve.

A flow diagram of this process is presented in Figure D-8.

EFCO Process --

The EFCO Process is a molecular sieve process developed by the Engineers and Fabricators Company. Sour gas enters the unit through a separator and filter which removes all liquids and entrained solids. The gas then flows downward through two molecular sieve beds and leaves the plant as sweetened gas. A portion of the sweet gas stream is removed and flows downward through a third bed which has been regenerated but it is still hot. The sweetened gas removes heat from the bed and flows through a gas-to-gas exchanger before going through the regeneration heater. Following heating, this gas flows upward through the bed on regeneration cycle, heating it and removing the adsorbed H_2S and sulfur compounds. The gas from the bed then flows through heat exchange with the sweetened gas to the tower and then through a cooler. The EFCO process rejects from the gas stream only the acid gas constituents and burns only the amount of gas required to provide regeneration heat.

STRETFORD PROCESS

One final sweetening process is the Stretford Process. This process is described separately because it does not really fall into any of the other four categories. The gas is washed with an aqueous solution containing sodium carbonate, sodium vanadate, and anthraquinone disulfonic acid (ADA). The solution reaches equilibrium with respect to CO_2 in the gas and only relatively small amounts of CO_2 are removed by the process. Thus, the process represents an

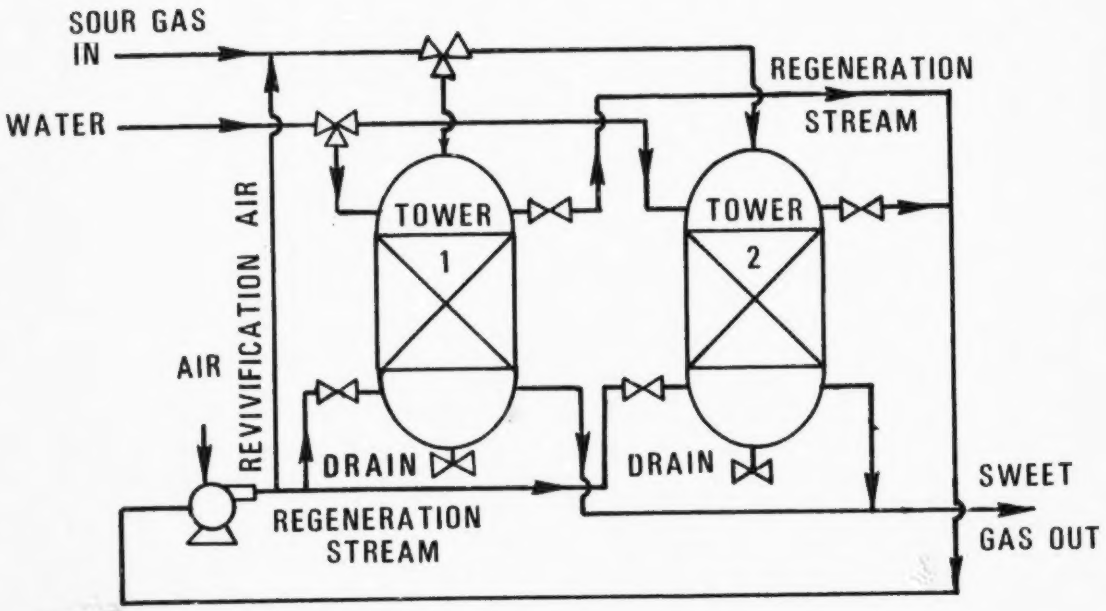

SOUR GAS IN
WATER
REGENERATION STREAM
REVIVIFICATION AIR
TOWER 1
TOWER 2
AIR
DRAIN
DRAIN
REGENERATION STREAM
SWEET GAS OUT

Figure D-7: Flow diagram of iron sponge process.(13)

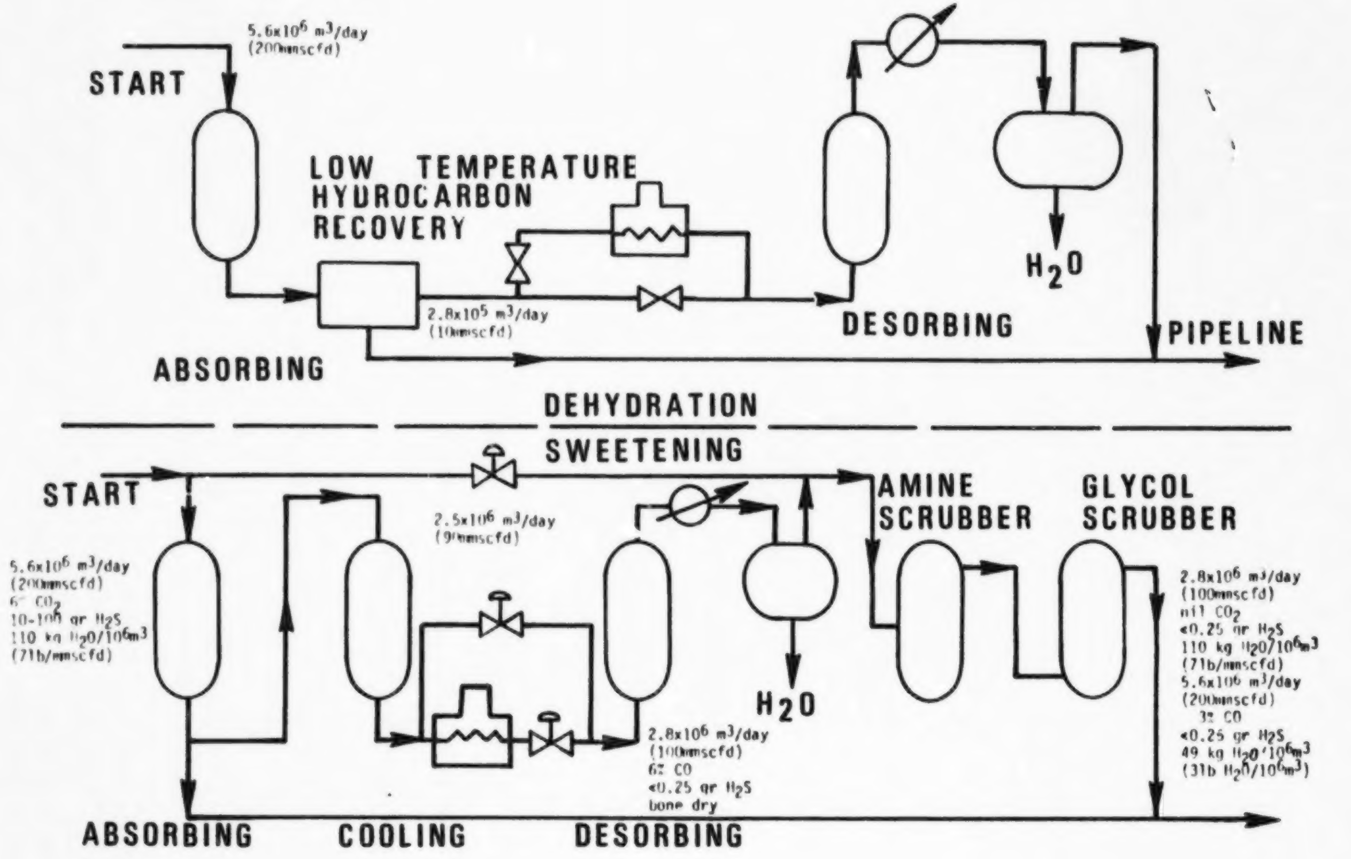

START
5.6x10^6 m3/day
(200mmscfd)
LOW TEMPERATURE
HYDROCARBON
RECOVERY
2.8x10^5 m3/day
(10mmscfd)
ABSORBING
DESORBING
H2O
PIPELINE
DEHYDRATION
SWEETENING
START
5.6x10^6 m3/day
(200mmscfd)
6% CO2
10-100 gr H2S
110 kg H2O/10^6m3
(7lb/mmscfd)
2.5x10^6 m3/day
(90mmscfd)
2.8x10^6 m3/day
(100mmscfd)
6% CO
<0.25 gr H2S
bone dry
H2O
AMINE
SCRUBBER
GLYCOL
SCRUBBER
2.8x10^6 m3/day
(100mmscfd)
nil CO2
<0.25 gr H2S
110 kg H2O/10^6m3
(7lb/mmscfd)
5.6x10^6 m3/day
(200mmscfd)
3% CO
<0.25 gr H2S
49 kg H2O/10^6m3
(3lb H2O/10^6m3)
ABSORBING
COOLING
DESORBING

Figure D-8: Flow diagram of molecular sieve process.(13)

economic route for sweetening sour, CO_2-containing gas with much less shrinkage than that associated with amine based processes.

The sour gas is cocurrently washed with regenerated liquor. The H_2S dissolves in the alkaline solution and is removed to any desired level. The H_2S formed reacts with the 5-valent state vanadium and is oxidized to elemental sulfur. The liquor is regenerated by air blowing, and the reduced vanadium is restored to the 5-valent state through a mechanism involving oxygen transfer. The sulfur is removed by froth flotation and the scum produced can be processed several ways depending on the desired end product, total sulfur produced and utilities cost. The reactions upon which the process is based are essentially insensitive to pressure.

The process can be written as follows:

Step 1: H_2S absorption
$H_2S + Na_2CO_2 + 1/2\ O_2\ (\text{air}) \rightarrow NaHS + NaHCO_3$

Step 2: Sulfur precipitation
$2NaVO_3 + NaHS + NaHCO_3 \rightarrow S \downarrow + Na_2V_2O_5 + Na_2CO_3 + H_2O$

Step 3: Sodium vanadate regeneration
$Na_2V_2O_5 + \text{ADA (oxidized)} \rightarrow 2NaVO_3 + \text{ADA (reduced)}$

Step 4: ADA regeneration
$\text{ADA (reduced)} + 1/2\ O_2\ (\text{air}) \rightarrow \text{ADA (oxidized)}$

Overall reduction:
$H_2S + 1/2\ O_2 \rightarrow S + H_2O$

This process does not recover COS and CS_2.

A flow diagram is presented in Figure D-9.

MISCELLANEOUS CHEMICAL PROCESSES

Phosphate Process --

The phosphate process was developed by Shell. It employs a solution of potassium orthophosphate for absorbing H_2S. Regeneration is accomplished by steam stripping. It is a two stage absorption process in which the complete regenerated solution enters the final stage in contact with the effluent gases and the partially regenerated solution enters the first stage, thus saving steam.

Tripotassium Phosphate Process --

This process, also introduced by Shell, has been largely replaced by the amine process. It does have some advantages, however, for special applications: tripotassium phosphate is not volatile, it is insoluble in hydrocarbons, and it does not react with COS.

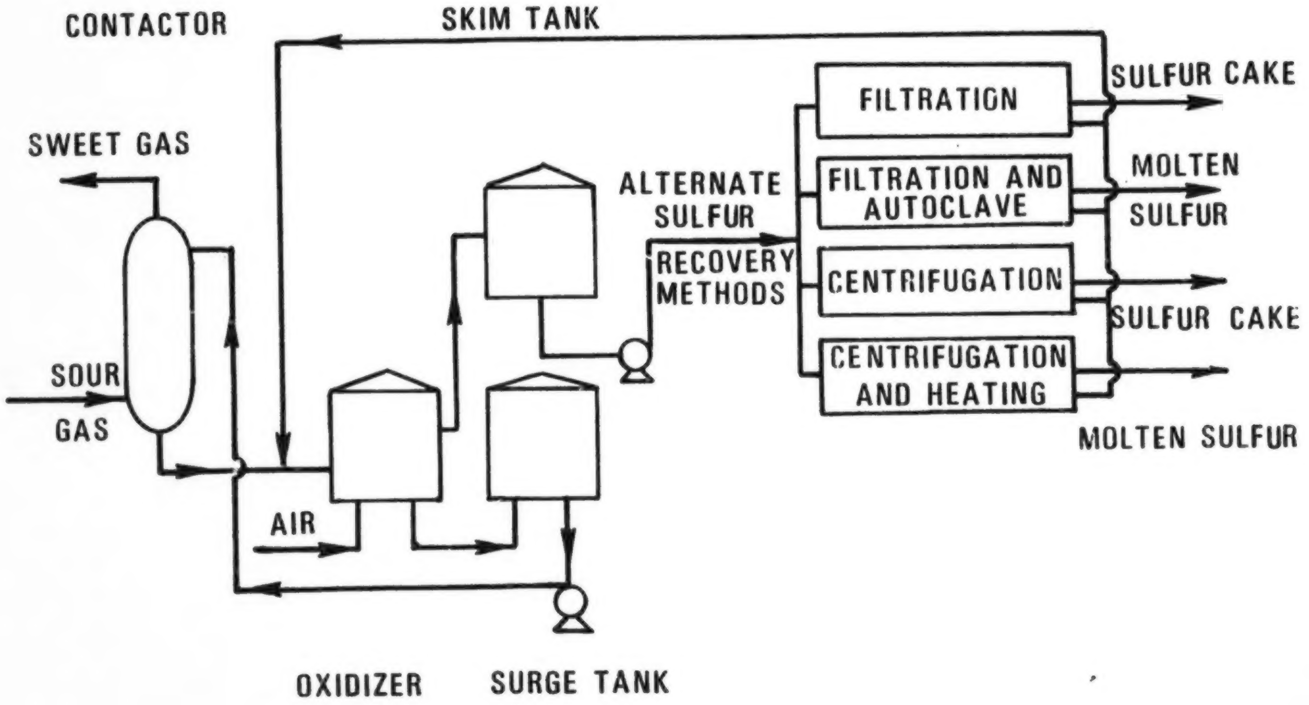

CONTACTOR
SKIM TANK
SWEET GAS
SOUR GAS
AIR
OXIDIZER
SURGE TANK
ALTERNATE SULFUR RECOVERY METHODS
FILTRATION
FILTRATION AND AUTOCLAVE
CENTRIFUGATION
CENTRIFUGATION AND HEATING
SULFUR CAKE
MOLTEN SULFUR
SULFUR CAKE
MOLTEN SULFUR

Figure D-9: Flow diagram of Stretford process.

Sodium Phenolate Process --

This is a process that involves a concentrated solution of sodium phenolate in a heat conversion-heat regenerative flow process. It has a high capacity for H_2S but, unfortunately, a low efficiency for H_2S removal. It can remove only about 90% of the H_2S in sour gas which is usually not enough to meet pipeline specifications.

Phenoxide Process --

This process is not used anymore due to operating difficulties. It used a solution of sodium phenoxide as an absorbent.

Alkacid Process --

This was a process used in Germany prior to World War II and is not presently used in the U.S.